EA-90-01

ENVIRONMENTAL ASSESSMENT BOARD

Ontario

ONTARIO HYDRO DEMAND/SUPPLY PLAN HEARINGS

VOLUME: 122

DATE: Wednesday, March 25, 1992

BEFORE:

HON. MR. JUSTICE E. SAUNDERS	Chairman
DR. G. CONNELL	Member
MS. G. PATTERSON	Member

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EA-90-01

ENVIRONMENTAL ASSESSMENT BOARD
ONTARIO HYDRO DEMAND/SUPPLY PLAN HEARING

IN THE MATTER OF the Environmental Assessment Act, R.S.O. 1980, c. 140, as amended, and Regulations thereunder;

AND IN THE MATTER OF an undertaking by Ontario Hydro consisting of a program in respect of activities associated with meeting future electricity requirements in Ontario.

Held on the 5th Floor, 2200 Yonge Street, Toronto, Ontario, on Wednesday, the 25th day of March, 1992, commencing at 10:00 a.m.

VOLUME 122

B E F O R E :

THE HON. MR. JUSTICE E. SAUNDERS	Chairman
DR. G. CONNELL	Member
MS. G. PATTERSON	Member

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MR. R. NUNN	Counsel/Manager, Information Systems
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D. COLBORNE		NIPIGON ABORIGINAL PEOPLES' ALLIANCE
R. CUYLER		ON HIS OWN BEHALF

INDEX of PROCEEDINGS

TIME NOTATIONS

---Upon commencing at 10:04 a.m.

THE REGISTRAR: Please come to order. This hearing is now in session. Please be seated.

THE CHAIRMAN: Ms. Harvie?

MS. HARVIE: I should mention, Mr. Chairman, I have here on the table additional new copies of page 24 of Exhibit 519. The document yesterday that you pointed out was not very clear on the photocopies. Mr. Lucas has helped himself to eight copies, and there are additional sets here for parties who would like to help themselves as well.

<u>DAVID WHILLANS</u>,
<u>KURT JOHANSEN</u>,
<u>FRANK CALVIN KING</u>,
<u>WILLIAM JOHN PENN</u>,
<u>IAN NICHOL DALY</u>; Resumed.

<u>DIRECT EXAMINATION BY MS. HARVIE (Cont'd):</u>

Q. Starting again you, Mr. King. Yesterday we went through the regulatory process and its role in safety management and you described the approach to reactor design from a safety perspective and how safety is managed in design.

So the next question I would like to ask you is about the systems in place that you have to manage safety and design operation and how do you know that they are working?

MR. KING: A. First of all, we have our

own audit systems in place which periodically review the performance of our stations in selected areas. Of course, there is always the AECB there to checkup on us to make sure that our nuclear safety management systems, the systems that I described yesterday, are in fact working.

However, if you want a more direct evaluation of our performance, you can always look at the record. We have only 20 years of experience in operating large power reactors but in those 20 years we have 200 reactor years of experience. This is still a small amount of experience with respect to the frequency of serious accidents that we looked at, hence you wouldn't expect to find serious accidents in that small time frame. But I think it is always useful to go back to the record and see what is happening in the field.

If you consider that the ultimate objective of nuclear safety is really to protect the public from large releases of radioactive materials, the record in Ontario Hydro is clean. What that means is that there has never been an event in any Ontario Hydro reactor which has resulted in any measurable health effect to any member of the public.

Also, we have never had an occurrence of

serious fuel failures due to the over-heating of the fuel and hence we have never had a large presence of radioactive materials released within containment.

Also, there has never been an occasion where we have needed the emergency coolant injection system, which I described yesterday, to actually function following an accident.

Q. Mr. King, I understand that the Atomic Energy Control Board has reliability requirements for special safety systems. What are they, please?

A. The AECB has established requirements for the four special safety systems, these are the two shutdown systems, the emergency coolant injection system and the containment system which I described yesterday. These requirements are in the form of unavailability targets, where unavailability is the fraction of the time where a system would not be available to do the job it's designed to do if called upon to do so.

When Pickering "A" was licenced, this AECB unavailability target was 3 times 10 to the minus 3. In terms which are perhaps a little more easy to understand, this is equivalent to an unavailability of 24 hours per year, or less than a chance of three in

1,000 that the system could not function and do its job if called upon to do so.

Subsequent to Pickering "A" being licenced, the AECB with their issue of their 1972 sighting guide made the unavailability requirement for the four special safety systems more stringent. In the '72 sighting guide they changed the requirement to one times ten to the minus three. Again, in terms more easy to understand, this is equivalent to an unavailability of less than eight hours a year, or less than one chance in 1,000 that the system would not be available to do its job.

These requirements that the AECB have established are very stringent. In fact, I am not aware of any regulatory body anywhere else in the world that has such a stringent sets of requirements for unavailability of safety systems.

Q. How do you know that these unavailability targets are in fact being met?

A. As I referred to briefly yesterday, there are tests which we put our systems through, I referred to the operational reliability monitoring program. This is where you, whether it's daily, weekly, bi-weekly, monthly, you make sure that the valves will open when they are supposed to, the pumps

will start when they are supposed to.

Most of the special safety systems are dormant systems, they are not involved in the production of power so they are waiting there for an accident to happen to perform some function.

If a single component is detected to be failed when you do such a test this does not mean that the system is unavailable. We would have prepared a significant event report, and I again talked about that system yesterday. If a single component would have been detected in the failed state, the system would not be unavailable.

It would normally require several redundant components, redundant meaning components which are all capable of doing the same job, to fail before a system would be declared to be unavailable.

However, if the system was found to be unavailable, then the time that it was unavailable would be estimated and compared against the AECB eight hour a year unavailability target.

The past unavailability record for each of the special safety systems or each of the stations is reported in the annual report, or it's also called the fourth quarter report for each station.

Q. And what has been Ontario Hydro's

record in meeting the AECB's special safety system unavailability targets?

A. Our record in meeting these targets is mixed. The record with respect to the shutdown systems is fairly good.

If you look at the last five years, let's say from 1987 to the end of 1991, as reported in these fourth quarter reports for each of the stations, you will note that for the first shutdown system, the rod drop system, at Pickering "A" and Pickering "B" and at Bruce "A", throughout all this five-year period there has never been an occasion where any system on any unit has exceeded its target.

On Bruce "B", in the four units at Bruce "B", there were two occasions two years over that five-year period where the target was exceeded for the second shutdown system, the liquid injection system.

I should have said the first shutdown system.

So on Bruce "B", if I could just clarify that, there were two years in the last five where there has been occasion where the annual unavailability target has been exceeded for the first shutdown system.

With respect to the second shutdown system, for all the Pickering "B", Bruce "A" and Bruce

"B" - you will recall that Pickering "A" does not have a second shutdown system - in the five years, '87 to '91, there has been six occasions where a second shutdown system on one unit of those stations did not meet its target.

The record with respect to the emergency coolant injection system and the containment systems is not at good.

The record with respect to the Bruce "A" ECI system in 1989 and the Bruce "A" containment system in the years 1987 through 1990, and the Pickering "A" and "B" containment systems in 1990 show large excedances of the AECB target.

I would like to go through these cases which I have just mentioned in some detail to give you a flavour of what it really means when a special safety system is declared unavailable.

In 1989 the Bruce "A" ECI system had an unavailability of 332 times 10 to the minus 3. You recall the target is 1 times 10 to the minus 3.

If I could refer you to a figure, we had this figure, this is on page 44 of the figure handout, I used this yesterday to describe the operation of the ECI system. I just want to bring your attention to the valve which is up in the upper right-hand corner, this

is a normally closed valve, isolating the nitrogen, high pressure nitrogen tanks from the light water tanks. When it opens it directs high pressure water into the heat transport system.

This valve which is normally closed is tested periodically to make that it will open and in fact open fast enough.

We were finding on testing this valve in 1989 that it was not opening as fast as it should. It has a requirement of opening within 20 seconds, and it wasn't opening that fast occasionally on the tests that were occurring.

The limit in the operating policies and principles document, the safe operating envelope limits which I referred to yesterday, was 20 seconds, and it was opening occasionally in the time a bit longer than 20 seconds. However, when this was detected we went back to the safety analysis which had established this 20 second limit, looked at it, we did some analysis and showed that in fact the ECI system would have functioned fully even if the valve were to open within 40 seconds. However, since the fact that we did exceed one of our own operating policies and principles limits, we declared the system to be fully unavailable.

If I could talk right now about the

Bruce "A" containment in 1987. The target being 1 times 10 to the minus 3, the actual being 385 times 10 to the minus 3, and in this case there was is a sump pump in the basement of the vacuum building. This sump pump has a small check valve associated with it and this check valve was found to be leaking.

If there had been a loss of coolant accident, there could have been water with a slight degree of radioactivity, not to the same degree as would be found within the reactor building, and there could have been a small leakage through this passing check valve. In this case we declared the containment system to be completely unavailable.

[10:17 a.m.]

In 1988 in Bruce A containment the actual was 266 times 10 to the minus 3. In this case there is a system which takes air from the reactor building atmosphere, puts it through dryers to take out the heavy water from the atmosphere, and brings it back into the reactor vault.

There's a small bypass from that which goes to atmosphere through filters in order to keep the containment pressure within the reactor building slightly subatmospheric.

In this line going outside the

containment envelope there is a detection system which detects high pressure or high activity. If either of these parameters exceed a certain value, then this whole vapour recovery system is isolated. There is a duplicate valve on each line which close and isolate the containment.

We found in 1988 that the activity monitor had been isolated by mistake and, hence, we declared the system to be unavailable. In fact, it's not as bad as it sounds in that if there would have been an accident involving high pressure, the high pressure monitor would have isolated the system.

Also the emergency operating procedures, this Abnormal Incident Manual which I referred to yesterday, one of the first steps following an accident, what the operator is directed to do is to make sure that the vapour recovery system is isolated and in fact, even with this activity monitor not in place, the containment could have been manually isolated from the control.

In Bruce "A" containment in 1989 the actual was 383 times 10 to the minus 3. In this case it was a transfer chamber which is an airlock type device which is used to primarily move equipment in and out of the reactor building. It's a vessel with

airlock doors with a rubber seal around the doors which expand and create a boundary. You open one door, you get in, you close that door, you open the other door and go into containment.

In one of the doors there is an equalizing valve, a small valve which is normally in the open position, it's supposed to be on the inner door on the reactor building side. On a pressure test which we periodically do to make sure the containment integrity can still withstand a high pressure, the inside of the transfer chamber was pressurized and on the outer door, the one away from the reactor vault side, one of these rubber expanding seals on the outside of the door came out of the groove a wee bit, the wrong seal had been inserted, and that would have led to a small flow path through this equalizing valve in the inner door, off this valve, this seal which had come out of the groove. So, again, we declared containment fully unavailable for that reason.

Moving on to Pickering "A". In 1990, a couple of years ago, the actual was 340 times 10 to the minus 3. In this case the target Pickering "A" is 3 times 10 to the minus 3, but since several aspects of the Pickering "A" and Pickering "B" containment are the same, the Pickering "B" unavailability limits takes

precedent so in fact it's really Pickering "A" and Pickering "B" containment issue I'm about to talk about.

There, if you recall, Mr. Penn's figure of the Pickering "A" station, the reactor buildings, there is the vacuum building, there is between them on a raised -- 20 feet off the ground there's a square pressure relief duct which connects all the eight vacuum buildings, all the eight reactor buildings. If there's an accident in any one of them this hot steam air mixture comes through the pressure relief duct and goes into the vacuum building.

We were doing a pressure test of containment and this long, whatever it is, half a kilometre long pressure relief duct, concrete duct, has expansion joints, it isn't poured as one whole element and periodically, to allow for concrete expansion, there's a rubber expansion joint. On pressurization of the pressure relief duct one of the expansion joints had a significant tear in it and we declared the containment to be unavailable for that reason.

We had tested the pressure up to the full design pressure of containment which was 42 kPa gauge or, in other units perhaps you're more familiar, it's 6 psig, that's the design pressure. In fact, the seal

failed at 22 kPa gauge or 3.2 psig.

However, the design pressure is set not by a lost coolant accident, not by a failure of the heat transport system, but in Pickering the steam mains are inside containment, inside the reactor building and there was a failure of the steam mains which set the design pressure, but with the steam main you don't get the radioactive materials put into containment as you potentially do with a loss of coolant accident.

Also, if there was a large loss of coolant accident, the peak pressure would have been 14 kPa which is only 2 psig, so even if you would have had the largest loss of coolant accident, that seal would not have failed, but we still declared the containment to be fully unavailable given that we didn't meet its design pressure.

Okay. I have just given you a full examples of the cases where there have been large excedances. We are not happy with the overall record because of these excedances in the containment in the CI area, but these targets are not by themselves a good indicator of increased risk.

In many cases, as I have discussed, the system performance would only be degraded somewhat and substantial mitigative capability would still be

available. Also, a special safety system is declared unavailability if it can't meet its design performance requirements for all postulated accidents. If it could meet its design requirements for all but the most unlikely and demanding postulated accidents it would still be declared fully unavailable.

On the more positive side, as a result of the quality improvement process which Mr. Daly talked about in his evidence, the trend in the last three years has shown a reduction in the number of occurrences when special safety systems have not met their unavailability targets.

Q. Mr. King, of all the events that have occurred, what is the most serious event that has taken place in Ontario Hydro's reactor program?

A. Well, perhaps the most serious event that has occurred was the pressure tube failure which occurred at Pickering "A" Unit 2, channel G16, in 1983.

You'll recall that Mr. Daly discussed the causal mechanisms of this event in some detail, but just to refresh your memory, this is the overhead that he used, this is on page 17 of your handout.

The only difference between this diagram and the fuel channel at Pickering is that - and as pointed out by Mr. Daly - that the Pickering 1 and 2

units have only two garter springs not the four as shown on this diagram.

What happened, there was a rupture of the pressure tube due to the sagging and contact with the calandria tube and the formation of blisters that was described by Mr. Daly.

The calandria tube held, it did not rupture, there was small loss of coolant accident from the ends of the channel through a ruptured bellows. The bellows is a metal expansion joint which keeps in the anulus gas essentially and allows for some thermal expansion of the fuel channel with respect to the calandria structure. So there was a small leakage out of each end through the bellows onto the floor.

We have a system called a D2O recovery system which is not a special safety system, but it does a similar job to the emergency coolant injection system, picks up heavy water from the floor and puts it back into the heat transport system.

After the reactor was shut down manually the shutdown systems -- there was no need for them to operate automatically, the reactor was shut down manually. The operators initiated the D2O recovery system and there was no need for the emergency coolant injection system to come in either.

And the reactor was cooled down, shut down and the circuit with the heavy water being picked up off the floor with the D2O recovery system was put in place.

[10:30 a.m.]

This G16 event initiated a massive inspection program on other reactors, research activities and ultimately ended up in pressure tube replacement programs which have been described.

All of this with the intention of preventing any G16 type of event from occurring in the future.

Q. What plans are in place if there was a serious accident?

A. If there was a serious accident with potential for off-site releases there are emergency plans in place to respond to the situation.

The legal basis for emergency planning and response in Ontario is the Provincial Emergency Plans Act. This Act establishes the Solicitor General of Ontario as responsible for off-site emergency planning.

The Ministry of the Solicitor General has subsequently issued a document called Province of Ontario Nuclear Emergency Plan, Plan 1, which is

generic to all reactors. It has also issued plans specific to each reactor.

These plans establish the responsibilities for each of the participating organizations, various municipalities, the various government ministries, local municipalities, as I said, Ontario Hydro. These plans are also exercised regularly.

Typically, each shift crew, again I referred yesterday to five shift crews on a reactor, would train with respect to their functions in a plan several times a year, and they would also have a formal exercise with observers once a year. There would be a major exercise at each station once a year to test all the response groups at the station.

There would also be, organized by Ontario Hydro, a large corporate exercise once a year rotated amongst the various stations. And this would exercise all the key groups, not only those at the station but throughout Ontario Hydro.

There would be either participation from the Ministry, Solicitor General and local municipalities directly or via role playing. What I mean is they don't have their whole organization in place, they just have somebody role playing their whole

organization.

That's with respect to the Ontario Hydro annual exercise.

The province themselves periodically have large provincial exercises which fully test all the other aspects, the non-Ontario Hydro parts of the plan. And this large provincial exercise would rotate amongst the various sites.

Ontario Hydro also has emergency plans for the transportation accidents involving radioactive materials, and these are exercised on an annual basis as well.

Transport Canada here is the government body which has jurisdiction with respect to transportation accidents, and it is to Transport Canada that we submit our emergency plans with respect to radioactive transportation accidents.

Q. As we all know there have been several significant reviews of the safety of Ontario Hydro's reactors conducted by external agencies. Mr. King, I wonder if you care to discuss these in a little more detail, please.

A. Well, in addition to the AECB, which is an external agency and is continually reviewing the safety of all our reactors, there are several other

reviews of Ontario Hydro's nuclear program which drew conclusions with respect to nuclear safety.

In particular, the Select Committee on Ontario Hydro Affairs, the Operational Safety Review at Pickering which was organized by the IAEA, International Atomic Energy Agency, and the Ontario Nuclear Safety Review, which is headed up by Dr. Kenneth Hare. If I could go through these one by one.

In its June 1980 final report on the Safety of Ontario Hydro Reactors, the Select Committee on Ontario Hydro Affairs stated that:

> On the basis of evidence examined so far, the nuclear reactors operated by Ontario Hydro are acceptably safe.

Moving on to the next one, 1987, the 12 member IAEA appointed Operational Safety Review Team, know as OSRT, performed a review of Pickering operation as invested by the provincial and federal governments. Their report states that:

> OSRT was satisfied to find all the equipment, personnel and resources necessary at Pickering nuclear generating station to ensure continued safe operation of the station.

And finally, in 1988 in his report to the

Minister of Energy, Dr. Hare's first conclusion was that:

The Ontario Hydro reactors are being operated safely and at high standards of technical performance. No significant adverse impact has been detected in either the work force or the public. The risk of accidents serious enough to affect the public adversely can never be zero, but is very remote.

Q. Mr. King, are you convinced that Ontario Hydro's nuclear power plants can be operated safely now and until the end of their service lives?

A. The short answer to that question is yes.

What is needed to ensure safety in the long term is a basic soundness of design, it needs institutions and processes in place to foster safe operation. To do this, you need an operating organization with a strong safety culture, with open debate and with internal self-correcting mechanisms.

I think you also need a strong, independent regulatory body, but I believe that all of these are in place and, yes, I am convinced that we can continue to operate our reactors safely.

Q. Thank you.

Mr. Johansen, I am going to ask you some questions about the natural environmental implications of the nuclear generating system.

Would you begin, please, giving us a brief overview of the scope of the evidence that you will be presenting this morning.

MR. JOHANSEN: A. Yes, I propose to cover three main areas. First, how nuclear power is regulated and managed for protection of the environment; secondly, a general description of the different types of emissions and effluents associated with our nuclear operations, and our performance in controlling the effects of these emissions and effluents on the environment, and thirdly, how Ontario Hydro currently manages radioactive materials that result from our operations and we how we plan in future to continue managing and disposing of these materials.

Q. Dealing then with the first category. As we have heard from Dr. Whillans and Mr. King, we have heard about how the regulation nuclear power for health and safety purposes is managed, how is nuclear power regulated in Ontario for environmental protection purposes?

A. Environmental protection is regulated

at both the provincial as well as the federal level. The major provincial environmental legislation applicable to our current operations are the Environmental Protection Act and the Ontario Water Resources Act.

The main applicable federal legislation includes the Atomic Energy Control Act which we have already talked about to a considerable extent, as well, there is the Canadian Environmental Protection Act and the Transportation of Dangerous Goods Act. There are number of others, but these are the mains ones.

Under these provincial and federal acts there are a lot of regulations, codes of practice, and guidelines that either limit or have significant bearing on Ontario Hydro's projects and operations.

Following environmental assessment approval and Atomic Energy Control Board approval to construct a nuclear facility, a nuclear project would still require several environmental permits and approvals in addition to the operating licence that Mr. King talked about.

These environmental permits and approvals include things like a permit to operate equipment like combustion turbine units that are used to drive the standby generators at our nuclear facilities; a permit

to operate a waste management system or a waste management site, and these are all under the Environmental Protection Act; we need permits to take cooling water from the Great Lakes or another water body if that were the case; we need a permit to discharge cooling water back into these Great Lakes or other water bodies, and we need permits to discharge effluents from our liquid waste management systems, and these are all under the Ontario Water Resources Act. There are a number of others at both the provincial and federal level that we have to obtain before we can commence a new project.

These permits have to be reviewed periodically and renewed, depending on what the site-specific conditions of approval are.

Under the conditions of these permits we are typically required to submit to the Ministry of the Environment monthly environmental monitoring reports, as well as annual summary reports.

Q. How is environmental protection managed by Ontario Hydro?

A. Our corporate environmental policy and management system are described in some detail in Exhibit 256 which is the 1990 edition of our corporate environmental performance report or what we used to

call the State-of-the-Environment Report. Panel 2 provided an overview in the context of the total existing power system.

There are a couple of areas that I would like to emphasize here in the context of nuclear environmental protection management. The first is the extensive monitoring and reporting that we routinely carry out, and secondly is our ongoing management of radioactive materials and advanced planning for the eventual disposal of these materials.

Q. Would you discuss monitoring in greater detail, please.

A. Yes, I propose to talk about first of all, the monitoring for radioactive emissions and effluents and then monitoring for non-radioactive emissions.

Radioactive emissions from our existing nuclear facilities are monitored by both in-station instruments, or what we refer to as the emission monitoring system, and by monitors located in the surrounding area around our facilities, and we refer to this as our environmental monitoring system.

In-station monitoring is routinely carried out on all of the gaseous and liquid streams that have the potential to exceed our operating target

for emission control; that is the 1 per cent of the derived emission limits.

Airborne emissions are monitored continuously and liquid effluents are monitored prior to any discharge.

The results of these routine monitoring efforts are analyzed weekly for airborne emissions and they are analyzed monthly for waterborne emissions, and this is to ensure that the emission rates remain normal; that is to ensure that we don't discharge a significant proportion of the annual emission amount that we are allowed over a relatively short period of time without taking some control action.

For those streams that might potentially contain enough radioactive material to exceed a derived emission limit, special monitoring and warning is provided to the control room so that the operators can take appropriate control action to ensure that the regulatory limits and our 1 per cent operating targets aren't exceeded. I will have more to say later on about our actual performance in controlling emissions to less than the 1 per cent operating target.

Q. All right. Dealing with Hydro's 1 per cent operating target, is there a regulatory requirement in the station licences that Hydro not

exceed 1 per cent the derived emission limit?

A. No, there is isn't. The regulatory requirement is that we not exceed the derived emission limits, and this is to ensure that we don't exceed the annual public dose limit which is the primary requirement.

These derived emission limits, or DELs, are calculated by Hydro for each station and they are documented in station specific reference plans which are directly referred to in the conditions of the operating licence for each station.

Hydro's operating policies and principles, which Mr. King referred to, are also referred to in the operating licence conditions, and these state that if we were to frequently or significantly exceed this 1 per cent operating target, then a review of the need and practicality of modifications to either equipment or procedures would be initiated. So, this is a Hydro operating guide which has been endorsed by the AECB. However, it's clear from the licence conditions that the regulatory emission limit is the derived emission limit, not the 1 per cent operating target.

Q. You mentioned the environmental monitoring system, that is the monitoring of emissions

in the area surrounding the station, would you describe that monitoring system in more detail, please.

[10:45 a.m.]

A. Yes. In addition to the in-station emission monitoring, Hydro carries out monitoring for radioactivity around all of the nuclear facilities and monitoring is also conducted at remote locations in Ontario to establish the background levels.

These environmental monitoring programs are also a condition of the AECB licence and results must be reported to the AECB.

Hydro's environmental radiological monitoring programs are designed to obtain data to assess on an ongoing basis the radiation exposures to the public resulting from airborne and waterborne emissions from our nuclear operations.

Radioactive emissions from our facilities may reach the public through a number of routes or pathways through the environment and my first overhead, which appears on page 45 of your package, Exhibit 519 that is, illustrates this pathway model that we use.

The box at the left of the overhead labelled source is our nuclear facility, of course. The box at the right-hand side, the far right, represents the radiation dose to a member of the most

exposed group in the surrounding population and this is the critical group that Dr. Whillans referred to yesterday.

All of the boxes inbetween represent different compartments, if you will, compartments of the environment and these compartments tend to reduce the concentration of the radioactivity received prior to passing that radioactivity on to the next compartment or on to the exposed population. For example, dilution and decay in the atmosphere or water body.

The lines and arrows inbetween the boxes represent various pathways along which the radioactive emissions may be conveyed towards the critical group.

So, in overview then, the total dose that the critical group may receive could potentially be a combination of external exposure from airborne emissions directly plus external exposure from airborne emissions deposited on the ground or other surfaces, plus ingestion of drinking water affected by our airborne or waterborne emissions, plus ingestion of food affected by these emissions.

This diagram, of course, is a general picture only of the environmental pathways but illustrates the concept. Every site situation is

different in detail.

So in order to assess public exposures via these pathways on an ongoing basis, samples and measurements are taken regularly around the nuclear sites corresponding to these different compartments of the environment in the pathway model that I just showed, and typically this sampling includes sampling of air, precipitation, drinking water, both municipal and private supplies, milk which has been locally produced, raw lake water, fish, sediments, farm produce, fruit, vegetables, things like that.

I should add that produce from commercial aquaculture or or greenhouse facilities that receive warm water or steam from our nuclear operations are included in this sampling program as well. But our standard procedure is to formally review these environmental monitoring programs every three years or so.

Hydro also operates meteorological monitoring systems at each nuclear site and this is to obtain site-specific weather data for dispersion analysis which is used in the safety assessments that Mr. King talked about.

And, finally, Health and Welfare Canada and the Ministry of the Environment of Ontario conduct

routine monitoring in the vicinity of our nuclear facilities as well and Environment Canada periodically conducts measurements right across the country to help establish background levels.

Q. You mentioned non-radioactive emissions as well, Mr. Johansen. Could you briefly outline Ontario Hydro's monitoring of these emissions?

A. Yes. There aren't any non-radioactive atmospheric emissions from our nuclear generating stations themselves that need to be monitored, but we do carry out routine air monitoring for hydrogen sulphide and sulphur dioxide emissions around our Bruce site and this is because we have the heavy water plant and the steam plant operations there and we have got seven environmental monitors, seven for hydrogen sulphide and seven for SO(2) around the Bruce site and, in addition, there is a monitoring station operated by the Ministry of Environment in that area as well.

We also monitor odour complaints around the Bruce heavy water plant and we even monitor for noise complaints even though our nuclear operations don't tend to be a source of intrusive noise.

On the water side there are a number of non-radioactive effluents that we monitor and these

include things like cooling water discharge temperature, both absolute temperature and temperature rise across the plant, and discharges from conventional liquid waste management systems including the effluent process water lagoon at the heavy water plant.

And, finally, under the province's MISA program and, again, this is the strategy, the Municipal Industrial Strategy for Abatement of liquid effluents, under the MISA program we have carried out an intensive program of monitoring of non-radioactive effluents from all of our nuclear facilities as well as fossil and hydraulic facilities.

Q. And to whom do you report all this monitoring of radiological and non-radiological emissions to?

A. Radioactive emissions are routinely reported to the Atomic Energy Control Board every quarter and they are summarized and assessed annually. The annual reports are distributed to the AECB and to a number of other federal and provincial agencies as well.

For example, our annual environmental summary reports issued by our nuclear operations branch go to Environment Canada as well as to the Ontario Ministry of the Environment and the Ministry of Natural

Resources.

The annual summary and assessment of environmental radiological data which is issued by the health and safety division goes to Environment Canada and Health and Welfare Canada, plus the Ontario Ministries of Environment and Labour and local municipalities and a number of other interested stakeholders.

And, finally, our corporate annual environmental performance reports have much wider circulation.

Non-radioactive emissions and other environmental performance parameters are routinely reported to the Ministry of the Environment every month and they are summarized annually. Again, these annual reports are widely distributed.

So, in summary, monitoring, reporting and, if necessary, remedial action are key functions in any environmental impact management process. Hydro's monitoring and assessment achieve a number of objectives in that they provide assurance that the public health and environment are protected, they provide confirmation of the models that we use in deriving emission limits, they provide evidence of our compliance with these emission limits, and they provide

a warning to the station operators of control action where required.

Q. All right. Well, you've told us about monitoring. I would like to ask you now about the environmental performance of Hydro's existing nuclear system and the effects of those emissions on the natural environment.

Would you describe, first of all, the kind of emissions that are typically associated with nuclear generating stations?

A. Yes. I would like to describe these in four categories. First and foremost, of course, are the routine controlled radioactive emissions to air and water from normal operation of our nuclear stations and from related facilities, related facilities include the radioactive waste operations site at Bruce and the tritium removal facility at Darlington.

Although these stations and facilities are designed to emit very small amounts of radioactivity, there are many potential leakage points in any complex plant. The design anticipates that these leaks will occur from time to time, so emissions to the environment are controlled through a combination of controls and monitoring including leakage recovery, liquid waste hold-up and treatment, airborne emission

hold-up and filtration.

Typically airborne emissions include radionuclides such as tritium, noble gases, radioactive isotopes of iodine, particulates and carbon 14. Tritium, as most of you probably know, is an isotope of hydrogen which is produced when heavy water is irradiated in the reactor.

The noble gases are isotopes of elements like xenon and argon which are produced either in the fission process, in which case we refer to them as fission products, or through irradiation of air or other materials in the reactor, in which case we refer to them as activation products. Radioactive isotopes of iodine are fission products as well.

The particulates group includes isotopes of elements like caesium, zirconium, cobalt and so on which are produced either in the fission process or through activation in the reactor system.

And finally carbon 14 is produced mainly by irradiation of oxygen in the reactor system or irradiation of trace impurities in the fuel or the fuel planning.

Waterborne emissions include tritium, again, plus a number of dissolved and suspended fission and activation products which are measured as total

radiation from beta particles and gamma rays or referred to commonly as gross beta gamma.

The second category of emissions that I would like to talk about is the emissions from our nuclear facilities of the non-radioactive emissions, that is to air from the heavy water plant operation and from the steam plant at Bruce, as well as minor emissions from the combustion turbines that drive the standby generators at each site.

The third category is cooling water which we draw from the Great Lakes at each site and discharge back to the lake at a higher temperature which we refer to as thermal discharge.

The fourth and final category includes non-radioactive waste water effluents from various process at the generating facilities and other facilities. We provided a lot of information on nuclear emission sources, our control performance and our assessment of effects in documents such as Exhibit 4, which was the environmental analysis accompanying the original DSP Plan, other documents were Exhibits 19 to 22 and 256, these are the annual environmental performance reports or State-of-the-Environment Reports as they used to be called.

And recently we have documented a lot of

information in Exhibit 507 which is the document entitled Materials Relating to Environmental and Health Effects of Nuclear Generation, and a lot of information has gone out through the interrogatory process.

Q. All right. Well, regarding radioactive emissions, what are the levels that have been typically measured as compared against the regulatory limits?

A. Our records, going back to the beginning of our nuclear operations over 20 years ago, show that we have consistently controlled our emissions from each facility to less than 1 per cent of the regulatory annual emission limits and this includes emissions from the radioactive waste operations site at Bruce and the tritium removal facility at Darlington.

The radioactive emission trends for some of our nuclear facilities over a five-year period from 1986 to 1990 are illustrated by a number of charts in Exhibit 519, pages 46 to 49.

My next overhead is based on the first of these charts and I don't propose to show them all because they are all quite similar and they are all fairly busy, I'm afraid.

We don't need to get into the complexity of the charts but, in overview, each of the charts in

the package referred to shows monitoring performance for the different groups of radionuclides that we routinely emit and monitor.

[11:00 a.m.]

These are the ones that I referred to earlier, tritium, noble gases, iodine, and particulates going to air, tritium and gross beta going to water.

This particular overhead is similar to the one that Dr. Whillans showed yesterday, and it shows a set of bar charts for Pickering "A". The height of each bar in each small chart represents the annual emission total for the particular radionuclide group for each year, 1986 to '90. Each chart has a line drawn across the top representing the 1 per cent of annual emission limit.

The main thing to note in all of these charts is that the bars in all cases are below that 1 per cent target line, and in many cases quite a bit below.

They three other charts in the handout, pages 47 to 49, which I won't show, illustrate similar trends for Bruce GSA, the waste operation site at Bruce and for Darlington.

In the case of Darlington, of course, we don't have a five-year trend as that plant only came

into service in 1990, so that's all we have to show.

Similar trends can be seen in charts for all of our other nuclear facilities published in our annual environmental summary reports. The annual emission totals are consistently below the 1 per cent target. I guess that is all I can say about that.

Q. Well, even though these limits are already very low as we can see from looking at the tables, is Hydro doing anything to reduce them further?

A. Yes. I have already talked about the tritium removal facility at Darlington, tritiated heavy water from all of our nuclear plants will be treated there, and we expect that that will result in a significant reduction in tritium emissions in future.

We are looking at improving the leak tightness of heavy water piping systems and improving the heavy water recovery systems at our various plants.

In addition, there are a number of research and development activities that were listed in Exhibit 256, and these include things like better methods for testing of airborne emission filters, improvements in liquid waste management systems, and we are also in the process of evaluating the feasibility of upgrading the waste volume reduction facility at Bruce, rad waste operation site. And while the

feasibility of these and other options for reducing emissions haven't yet been established in all cases, these kinds of evolutionary improvements are quite consistent with our ALARA policy; that is our policy of maintaining emissions as low as reasonably achievable, taking social and economic factors into account.

Q. All right. As we heard from Dr. Whillans, we dealt with the health effects, his evidence dealt with human health effects, but I would like to know from you how these emissions have affected the natural environment.

A. This is a question which has recently been studied by a number of international scientific bodies that Dr. Whillans referred to, including the U.N. Scientific Community on effects of atomic radiation, or UNSCEAR; the U.S. Academy of Sciences Committee on the biological effects of ionizing radiation, or BEIR, as well as a International Commission on Radiological Production, ICOP.

In summary, the general consensus of these scientific groups is that the standard of radiation protection considered necessary for protection of human health is also adequate to ensure that the health of other biota in the ecosystem is not unduly at risk.

Although while it's acknowledged that individual members of these other biota in the ecosystem might be harmed, for example, in the event of a local spill, the general consensus is that this would not be expected to endanger the entire species or create a significant imbalance in the ecosystem.

Q. What about non-radioactive emissions from nuclear generation, how do they affect the environment? Referring back to the emission categories, and why don't you deal first with emissions from the heavy water plant and steam plant at Bruce.

A. Okay. I will begin by explaining why it is that we use hydrogen sulphide or H(2)S gas at heavy water plant.

Heavy water consists of deuterium plus oxygen instead of hydrogen plus oxygen, as in the case of ordinary water. Deuterium is a form of hydrogen with a proton and a neutron in the nucleus, whereas hydrogen only has a proton. So deuterium is heavier than hydrogen.

Heavy water or deuterium oxide occurs naturally in water at the ratio of about one molecule of heavy water for every 7,000 molecules of ordinary water.

The heavy water production process uses

H_2S gas to extract deuterium out of natural lake water. The initial production stage in the process, referred to as enrichment, takes advantage of the fact that deuterium tends to concentrate in the water at low temperatures and it concentrates in H_2S gas at higher temperatures. This enrichment stage is then followed by a series of distillation steps to increase the concentration of deuterium close to 100 per cent at which point we refer to it then as heavy water.

Most of the H_2S is then subsequently removed from the heavy water, recovered and recycled, but some residual H_2S is discharged to the environment.

There is a flare stack at the heavy water plant which we use to convert most of the atmospheric H_2S discharge to sulphur dioxide which is less toxic and has a somewhat higher odour threshold.

So typical emissions from the Bruce heavy water plant then include SO_2 from the flare stack, and small amounts of H_2S either from incomplete combustion at the flare stack, or from so-called fugitive emissions or leaks at various points in the heavy water plant process.

Most of the H_2S as I said is recovered and recycled except for controlled releases to the

flare stack and except for leaks. Propane is added to in the flare stack gases to maximize that conversion of H(2)S to SO(2).

Emissions from the Bruce steam plant are pretty typical of oil-fired industrial boilers, including SO(2). I should explain perhaps that the Bruce steam plant is used to augment the steam supply from Bruce GSA which Mr. Daly referred to yesterday, either for supply of steam to the heavy water production process or supply of steam to the adjacent Bruce Energy Centre.

Dr. Effer during Panel 8 already talked about the effects of SO(2) and other pollutants associated with the combustion of fossil fuel, so I don't propose to go into that again.

Regarding H(2)S, my next overhead which is page 50 of Exhibit 519, this overhead summarizes some of the evidence that we have seen in the literature on health and environmental effects of exposure to H(2)S; that largely was presented in a risk assessment that we did a few years ago on the Bruce heavy water plant, and this risk assessment was issued in response to Interrogatory 9.21.1.

This table shows a range of effects associated with exposures to different concentrations

of H_2S for periods up to an hour, and looking from the bottom of the chart up, the evidence indicates to us that death in humans and domestic animals occurs rapidly at 500 parts per million, or PPM. It indicates that there are no serious irreversible health effects in humans or domestic animals from exposure to about 100 PPM for up to an hour.

Effects below this level tend to be limited to things like irritation of the eyes and the respiratory tract.

There is no significant evidence of damage to plants or crops below about 40 PPM. And most people can smell down to about 0.15 PPM, although the odour threshold can be lower in very sensitive individuals.

So, in summary, in comparison to the regulatory Ministry of the Environment criteria for ambient air quality, that criterion being 0.02 PPM on an hourly average basis, or 0.02 PPM, same number, on and a half hourly basis at ground level or other points of impingement. This regulatory criterion is many times lower than levels which we understand are required to cause death or serious health effects in human or domestic animals. It's many times lower than levels required to cause significant damage to plants

or crops, and it is even lower than the levels that most people can smell.

Continuous monitoring around the Bruce site over the years has shown that both H(2)S and SO(2) concentrations are generally very low, well below the regulatory criteria for ambient air quality.

The half hour point of impingement standard which I referred to for H(2)S, is exceeded very infrequently. For example, it was exceeded once in 1990, but not by very much. In that particular case it was .024 PPM as compared to the criterion of .02.

Nevertheless, there have been a number of odour incidents over the years reported by employees and by members of the public. Most frequently in the early years of heavy water plant operation, for example, in 1973 when the first plant, the "A" plant came into service, we had something like 50 reported incidents.

Typical causes of odour incidents include H(2)S leaks at the enriching units of the heavy water plant. They can also be caused by incomplete combustion at the flare stack, and occasionally we get odour from activities at Bruce that are completely unrelated to the heavy water production process, for example, unloading of the heavy oil for the steam

plant.

The frequency of odour incidents has decreased substantially over the years as our monitoring and emission controls and general operating experience have improved.

Q. Would you describe the typical cooling water system and how it affects the environment, please.

A. Yes. Panel 8 described the basic steam cycle and related once-through cooling water systems that we use at all our of thermal and nuclear plants. And I would like to take another look at the overhead that Mr. Penn used yesterday. This was the simplified CANDU unit flow diagram which appears on page 5 of the overhead package, Exhibit 519.

Just briefly, this diagram, or at least the part that I would like to refer to, illustrates three straight flow circuits. First of all, there is the heat transport circuit between the reactors or the boilers or the steam generators. And secondly, there is the steam and condensation circuit. Steam flowing from the boilers, or steam generators, to the turbines, where it's condensed and water is then returned to the steam generators.

Thirdly, and this is the key I guess for

my part, is the open cooling water system whereby cooling water is taken into the condenser where it picks up heat from the steam before being discharged back to the lake at somewhat higher temperature.

I just want to emphasize a separation between the open cooling water system and the reactor circuits. I guess that's sufficient.

The nuclear plant requires more cooling water per megawatt of electricity produced than a fossil fuel plant, something like 50 per cent more than a fossil plant. There are two main reasons for this. First of all, the lower temperature and pressure conditions in a typical CANDU steam cycle result in a somewhat lower overall efficiency. And secondly, a fossil plant emits about 15 per cent of its fuel, energy up the stack, whereas a nuclear plant doesn't.

Hydro's cooling water designs have evolved considerably over the years in light of a program initiated in the mid-70s to improve the design of cooling water systems, to minimize aquatic environmental effects.

Exhibit 507 summarizes the different cooling water system arrangements at our nuclear sites.

Pickering "A" and "B", for example, share a single channel type intake and they have separate

channel type discharges.

Bruce "A" and "B" have separate offshore submerged intakes and channel type discharges. These were generally illustrated in the photos that Mr. Penn showed yesterday.

The Darlington cooling water system represents what we consider to be the state-of-the-art, in once-through cooling design, including an offshore submerged diffuser type discharge, as well as an improved off-shore intake design. And Dr. Effer and Mr. Dawson during Panel 8 described the particulars of this design, so I don't propose to go into that again.

Q. What are the environmental effects of these cooling water systems?

A. Again, during Panel 8 Dr. Effer described the environmental concerns associated with once-through cooling. In terms of cooling water intake effects he talked about entrapment, impingement and entrainment, and he talked about effects at the other end of the pipe, you might say, the cooling water discharge effects related to heat. And nuclear plants are similar to fossil plants in this regard.

Based on the results of years of study and the once-through cooling improvement program which was initiated in the mid-70s and carried through to the

early 80s, plus the results of site-specific environmental studies, it is our conclusion that lake-wide adverse effects are insignificant and local effects are minor.

Exhibit 507 presents more detailed evidence on this issue, and we provided considerable information through the interrogatory process.

Finally, I would just like to note that Hydro does supply warm water and steam for other beneficial uses, for example, at Pickering we supply warm water from the condenser cooling water discharge to a commercial aquacultural facility adjacent to the site. At Bruce we supply steam from the Bruce complex to a greenhouse facility at the adjacent Bruce Energy Centre.

Q. Thank you. Referring now to your fourth emission category, your fourth and final, what are the sources of waste water effluents at a nuclear plant and what is Hydro doing to control them?

A. Well, routine effluents from our nuclear facilities include controlled discharges from the active liquid waste managements systems and from a number of fairly conventional, non-radioactive streams.

As indicated earlier, the active liquid waste management systems are designed to control

discharges to less than 1 per cent of the regulatory emission limits. Non-radioactive waste water streams from the nuclear stations include things like water treatment plant effluent, boiler blowdown, oily water treatment effluent, laundry and sewage treatment effluent, yard drainage and that sort of thing.

In addition, effluents from the Bruce heavy water plant includes controlled process water discharges either directly to the lake or via the process effluent lagoons, and this depends on whether the H(2)S concentration in the process water is high enough to be detected by the automatic monitoring and control system.

All of our nuclear plants as well as fossil plants use a number of conventional bulk chemicals in the various processes, where these chemicals combine with other chemicals or materials before being discharged at a controlled rate. For example, we use acids and alkalies in water treatment and these effluents are neutralized before discharge. We use ammonia and other chemicals to condition or control the chemistry of the boiler water and to prevent corrosion.

[11:20 a.m.]

We use chlorine in the treatment of

boiler water and in the treatment of domestic water as well as sewage effluent, and we have recently received Ministry of Environment permission to use chlorine in combating zebra mussel infestation on an interim basis until some alternative solution can be found.

So, in summary, routine waste water discharges are generally at low concentrations approved by the Ministry through the certificate of approval process. Non-routine discharges include periodic effluents from maintenance activities like boiler cleaning which are performed in a controlled manner with prior approval from the Ministry of the Environment.

Occasional spills of oil and other chemicals do occur and these are mostly recovered and are reported to the Ministry of the Environment also. More details on discharges and control performance are given in our annual environmental summary of reports which are issued to the Ministry of the Environment, to the Atomic Energy Control Board and others and, for example, a copy of this was given in response to Interrogatory 9.22.13.

Finally, as Dr. Effer indicated during Panel 8, Hydro is currently working with the Ministry of the Environment under the MISA program which I

referred to earlier and we are currently in the process of identifying the best available technology economically achievable basis for purposes of regulating the reduction of any toxic contamination in waste water from our facilities, and this is in keeping with the Ministry's ultimate goal of virtually eliminating persistent toxic effluents from industry and municipal discharges across the province.

MS. HARVIE: There's a third section to Mr. Johansen's evidence, Mr. Chairman, and that is dealing with the radioactive materials management. Shall we proceed on for the next 10 minutes?

All right.

Q. Mr. Johansen, you mentioned advanced planning earlier in your evidence in connection with the management of radioactive materials. Would you describe briefly what kinds of advanced planning Hydro is doing?

MR. JOHANSEN: A. Yes. We have done a lot of planning for long-term management of radioactive materials and issued a number of documents of these plans as they have evolved and these include an overview of the present management and plans for all of the radioactive materials that Hydro produces, and this document was provided in response to Interrogatory

9.9.41 and a number of others.

We have also prepared a plan for long-term management and disposal of used fuel and this document was provided in response to Interrogatory 9.41.6 and a number of others.

We have also prepared conceptual plans for decommissioning of our various nuclear facilities at Pickering, Bruce and Darlington and, incidentally, these are required as conditions of our operating licences, and a copy of the plan for Pickering, Bruce and Darlington decommissioning was provided in response to Interrogatory 9.6.8, and we are currently in the process of updating our plan for low and intermediate level radioactive waste.

These plans are important in ensuring that the technology and the resources are available when needed in future to continue managing the materials and protect the environment.

Q. In general terms, what kinds of radioactive materials are involved in Hydro's nuclear operations?

A. Well, there are those radioactive materials that result directly from our nuclear operations including the used nuclear fuel, low and intermediate level radioactive waste, or rad waste as

we refer to it, from the operation and maintenance and rehabilitation of these facilities, and eventually we will have so-called back-end waste when we begin to actually decommission these facilities.

In addition to there are what we might refer to as front-end wastes from uranium mining, refining and fabrication processes involved in supplying the nuclear fuel that we use.

Q. What is Hydro's position regarding radioactive wastes and effects of the so-called front end of the nuclear fuel cycle?

A. Well, in addition to maintaining responsibility for materials that we produce in operating our facilities, Hydro will deal only with licensed materials suppliers and contractors, we will stipulate full compliance with all government regulations as a minimum standard through contractual requirements, and we will consider an adjustment in the price payable for uranium or fuel if the supplier can demonstrate an increase in production costs due to a regulatory change, and this is a provision that we intend to ensure that the Hydro contract condition is not a deterrent to meeting regulatory requirements.

All suppliers involved in the supply of uranium and fuel have to comply with the AECB

requirements, they have to be licensed by the AECB and they are responsible for the control of radioactive materials within their possession, just as Ontario Hydro is responsible for controlling and managing the materials it produces in its operations.

The compliance with regulations by these suppliers is monitored by the Atomic Energy Control Board. Exhibit 507 outlines the nuclear fuel supply process in an overview fashion and provides some environmental and health effects of the process with a focus on the wastes and effluents from uranium mining and milling.

I should add that we did address front-end fuel cycle factors in our 1989 environmental analysis on the Demand/Supply Plan options in a generic comparative way which we felt was appropriate for a plan stage analysis.

Q. Now, how hazardous is used nuclear fuel and how is Hydro presently managing it?

A. In short, used nuclear fuel is highly radioactive and hot when it comes out of the reactor but the activity and heat reduce or decay substantially over time.

Mr. Daly yesterday showed what a typical CANDU fuel bundle looks like. Well, after about 18

months or so in the reactor a fuel bundle is effectively depleted and is removed from the reactor while new fuel is inserted to keep the nuclear energy process going.

While in the reactor a small part of the uranium in the fuel, and it's slightly over a per cent, is transformed into a number of new radioactive elements or isotopes. These are generally grouped into two categories, fission products and actinines.

Fission products are those isotopes which are formed directly in the fission process or through a subsequent decay or neutron absorption and they are characterized by high energy radiation and relatively short half-lives; hours, days, a few years. For example, strontium 90 in and caesium 137 have half-lives of about 30 years.

The actinine group includes all the heavy elements initially in the fuel plus those that form subsequently through the decay and neutron absorption process, and they are characterized by relatively weak radiation but longer half-lives. For example, plutonium 239 has a half-life of about 24,000 years.

After the used fuel is out of the reactor its radioactivity decays with time. For example, within an hour it loses more than half of its activity.

The activity decreases by a factor of about 50 after a year, by a factor of about 500 after 10 years, and it's predicted that it will decrease by a factor of about 50,000 after 300 years.

Most of the initial radiation comes from the fission products, but after about 300 years most of it will continue to come from the longer lived actinines.

After about 500 years in tact fuel bundles, in fact, could be handled without shielding and if they were placed in an underground repository the hazard from the fuel would be comparable in hazard to that from high grade uranium ore body.

Nevertheless, the long lived isotopes that remain in the fuel would be hazardous long after this and if inhaled or ingested, so used fuel certainly needs to be carefully managed and ultimately isolated so that it doesn't contaminate the environment in future.

Q. Can you go back to how Ontario Hydro manages used fuel.

A. Yes, okay. When the used fuel comes out of the reactor it's very radioactive and hot, as I said before and, therefore, it needs both shielding and cooling, and water-filled pools are an effective means

of accomplishing both and, for that reason, have been used and are being used at all of our nuclear facilities for initial storage at least.

From the reactor the used fuel is transferred to a so-called primary fuel bay within the plant. After about six years the fuel is cooled sufficiently that it can be transferred to some other facility on site for storage in the longer term. To date these auxiliary storage facilities have also been of the water-pool type.

My next overhead appears on page 51 of your package. This is a rather simplified diagram taken from our used fuel plan document. It illustrates the transfer of used fuel by remotely controlled fueling machines from the reactor to a primary fuel bay and later on from there to an auxiliary fuel bay.

Although this diagram doesn't show it, these bays are typically constructed with double walls with provision for collection of any leakage that might enter the space between the walls. Any leakage would then be drained to the bay water clean-up system and, in turn, returned to the bay and more detail on this design feature is given in Exhibit 43 on page 229.

Wet storage like this is the primary method for used fuel storage used throughout the world,

so our practice is consistent with what other utilities are doing and our studies have shown that fuel can be safely stored like this for at least 50 years.

MS. HARVIE: Would this be an appropriate time to take a break, Mr. Chairman.

THE CHAIRMAN: Thank you. Take a 15-minute break.

THE REGISTRAR: Please come to order. This hearing will take a 15-minute recess.

---Recess at 11:30 a.m.

---On resuming at 11:50 a.m.

THE REGISTRAR: Please come to order. The hearing is again in session. Please be seated.

THE CHAIRMAN: Ms. Harvie.

MS. HARVIE: Mr. Chairman, my estimate of how long the panel will be continuing to give evidence was a little overly optimistic yesterday.

I think we are unlikely to be finished before lunch, very unlikely to be finished before lunch, and probably will go as late as the afternoon break.

So I would like to let people know. I have spoken to Mr. Heintzman who is the first party up cross-examining and with Ms. McClenaghan who is bringing the motion.

Q. All right. Perhaps we can go back. We had an overhead that was just being placed on the screen and the question that I had asked was how Hydro presently manages used fuel, and Mr. Johansen had described the wet storage, and perhaps you can take it from there?

MR. JOHANSEN: A. Yes. I think I was just making the point that our studies on the wet storage technology indicated that we can continue safely using this wet storage technology for at least 50 years safely.

And my next overhead, which appears as page 52 in Exhibit 519, summarizes the total quantity of used fuel that we have accumulated to the end of 1990 at all of our nuclear plants and it also projects the total quantity that we forecast to the end of the lives of each of these existing facilities assuming that they operate for 40 years.

As shown in the second column from the left, the total used fuel accumulated to the end of 1990 is some 14,400 metric tonnes, which is equivalent to about -- well, a little over 700,000 fuel bundles.

The next column over indicates the in-service dates for the various nuclear plants.

The third and last column indicates the

forecast total, and the total lifetime accumulation from these existing plants is forecast to be about 75,000 metric tonnes, the number is shown at the bottom of the right-hand column, and this is equivalent to about 3.8 million fuel bundles.

And to put this into some kind of perspective that means something, the total volume is 75,000 metric tonnes. If placed in a standard hockey rink would fill that hockey rink to a depth of about 21 metres.

Additional storage facilities will be required at Pickering by 1993 and at Bruce by about 1997. At Darlington we won't require additional facilities until about 2010 at least.

The years of research and development with Atomic Energy of Canada Limited AECL going back to the 1960s have brought us to the point where we have now got two types of storage technology to choose from for purposes of additional storage. We have got the dry storage in special concrete based containers, as well as the conventional wet storage technology that I have already talked about.

This dry storage technology is being proposed for additional storage at Pickering, in fact, where we have been demonstrating two containers with

six- and 10-year old fuel since 1988 under AECB approval.

This dry storage method is also being used by AECL at the Douglas Point site where they have got fuel in storage that was taken out of the reactor at Douglas Point when that plant was shut down, and it's also in use by New Brunswick Power at their Point Lepreau station.

My next overhead which appears at page 52 in the handout, this overhead illustrates the design of our proposed dry storage container. What it shows basically is the design consisting of inner and outer steel shells filled by reinforced concrete inbetween these shells.

Each container stands about 3-1/2 metres high and is designed to hold 384 fuel bundles in four standard modules. The exploded view indicates what the standard module looks like and indicates a typical fuel bundle that would fit into that module.

After the dry storage container is filled with used fuel, and this would be conducted under water in the storage bays at the station, the lid would then be welded on to the container and the whole thing would be leak tested before the entire package is moved to a storage facility on the site.

Extensive studies by Ontario Hydro and AECL indicate that this dry storage technology can be used to store used fuel safely for at least 100 years. We submitted a safety analysis to AECB late last year for approval to proceed with the dry storage project at Pickering and we expect an AECB decision on this application later on this year.

I should point out that we have a dual purpose in going to dry storage technology. Our dry storage container in fact has been designed, in fact, not just for storage but it's been designed and tested to meet stringent international criteria for transportation as well, and these were conducted in June of '91 to early this year.

Talking about transportation, Hydro has had extensive experience in on-site transfer of used fuel between on-site storage facilities and we have been involved in a number of off-site shipments to research facilities since 1963, mainly to the research laboratories of AECL at Chalk River.

The shipment containers in all cases have been approved by the Atomic Energy Control Board. Over a span of about 30 years of operation amounting to something like 500 shipments of radioactive materials we have never had a transportation accident that has

resulted in any release of radioactive material.

So I guess the bottom line is that Hydro is managing its used fuel safely and we can continue to do so for decades at the existing facilities.

[12:00 p.m.]

Q. What plans does Hydro have for long-term management and disposal of used fuel?

A. The essence of Hydro's plan is to continue to store the used fuel at the nuclear stations until some future point in time when the used fuel can be transported to a disposal facility when that becomes available, and the target date in our plan for used fuel is that this disposal facility will be available, we assume, by the year 2025.

The Canadian Nuclear Fuel Waste Management Program was established in 1978 by an agreement between the Governments of Canada and Ontario. Under that agreement AECL was given the responsibility for developing and assessing a disposal concept, and Hydro had the responsibility for developing transportation and storage technology under that agreement.

I have already talked about our present and longer term storage technology development. In preparation for eventually disposal we are currently

investigating and assessing different options for large scale transportation of used fuel, this would be from storage to eventual disposal. We have looked at a variety of technologies including transportation modes by road, rail, water, or combinations thereof. We have developed, built, tested and obtained AECB design approval of a stainless steel transportation cask, which is illustrated in my next overhead, which appears at page 54 of Exhibit 519.

The main features to note are the solid stainless steel construction, its dimensions of approximately 2 metres cubed, and the impact limiter on the top which is designed to protect the lid bolts in the seal.

It's designed to hold two of the standard fuel modules that I showed earlier, that is 192 fuel bundles.

It's extremely robust, and we have proven this through a series of successful international tests that were intended to illustrate the effects of severe transportation accident conditions, crushing, penetration, fire tests, hydrostatic pressure tests and so on.

In addition to storage and transportation developments, Hydro has been contributing in many

technical areas of AECL's disposal development program, including assistance with environmental and safety assessment of the disposal concept, as that concept has evolved over the years.

The disposal concept which has been developed, basically involves placing the used fuel in durable, long-lasting metal containers. Right now the reference material for those containers is titanium, and then placing these containers in an engineered vault some 500 to 1,000 metres underground within rock formations of the Canadian Shield.

This concept is illustrated in my next overhead at page 55 of Exhibit 519. There are two diagrams there. The diagram at the top illustrates the general arrangement of shafts, access tunnels and disposal rooms in the overall repository facility. The diagram at the bottom shows a typical cross-section through one of the disposal rooms in the vault.

The current reference design has each disposal container placed in a bore hole surrounded by sand and bentonite buffer materials.

The disposal rooms would eventually be backfilled with mixtures of crushed granite, clays, sand and then sealed off from the access tunnels with heavy thick concrete bulkheads. And ultimately after a

period of monitoring, and once everyone is satisfied and confident of the performance of this facility, the whole vault, including tunnels and shafts, would be backfilled and sealed.

One disposal facility like this would be able to handle all of the fuel from Ontario Hydro that we project, and the fuel from other nuclear utilities in Canada.

Hydro plans to continue its support of the disposal development program towards the 2025 disposal target date that I talked about.

In the near term our support will be focusing on assisting AECL to complete an environmental impact statement for review through the federal environmental assessment and review process.

A review panel within that process has already been established, and in fact it produced a final EIS guidelines just very recently, earlier this month.

AECL haven't completed their EIS obviously as these guidelines have just been received, but it's my understand that they intend to show in their EIS that the technology does exist to safely, site, build and operate and eventually close and seal a disposal facility, that the methodology exists to

assess the performance of a disposal facility sited somewhere within the Canadian Shield in terms of the regulatory requirements for protection of human health and the environment.

MR. D. POCH: Mr. Chairman, I'm sorry, this seems to be all hearsay. He is telling us what the AECL tells us.

THE CHAIRMAN: Mr. Poch, it's been that kind of evidence all the way through the hearing.

MR. D. POCH: Mr. Chairman, if I may. This seems to me to be a central matter, the whole question of waste disposal and what test is being proposed, what is being proposed for this Board to review.

He has told us there is no environmental assessment statement available. He is telling us the speculations of another party, those materials aren't available for us to question or cross-examine on. I am not sure of the relevance of any of this anymore. Clearly, that is a matter you are going to have to wrestle within the context of the other motion.

THE CHAIRMAN: That whole matter is being dealt with by another body as well. Isn't that also a relevant consideration? It's a federal group dealing with the whole issue of disposal; isn't that correct?

MR. D. POCH: Perhaps my friends can tell us. Is it their assumption that this Board should just accept that that will be dealt with adequately and assume zero impact and zero risk. That could be the relevant evidence here. But I don't see the point of vague suggestions about what that impact is. Either they should present the evidence or take the position that it is not relevant to this hearing. But I am concerned that this kind of half measure discussion is just that, and it is a bit of a waste of time.

THE CHAIRMAN: Well, I am going to let them put it in. It is matter of a wait. Let them deal with their presentation. You can deal with it in cross-examination.

MR. D. POCH: Thank you, Mr. Chairman.

MS. HARVIE: Q. Mr. Johansen?

MR. JOHANSEN: A. To continue then.

Finally, AECL also, as we understand it, intend to show that there are many potentially suitable sites or rock formations across the Canadian Shield.

AECL has been planning to submit their EIS in 1993. Public hearings would follow sometime after that, and I think a government decision on acceptability of the concept could be reached very soon by about 1995.

The Canadian geologic disposal concept is consistent in our view with the direction taken in other countries.

Several countries are at advanced stages in development of disposal technology, and in fact, Sweden and Switzerland have both completed assessments of disposal technology, and they have concluded that deep geologic disposal can be developed safely using current technology and knowledge.

Assuming that government's decision on the Canadian concept is positive, and we are not prejudging that at all, there would still be a lot of additional developments, reviews and approvals required in order to actually have a repository in-service by the year 2025, and these are broadly outlined in my next overhead at page 56 in the package.

I guess it goes without saying that these dates are very approximate.

Again, assuming a positive government decision by 1995, there would have to be a government decision at that time, or shortly after that, as to who the disposal facility developer and operator will be, that is a decision that has not yet been made. Beyond that, the developer would have to undertake and complete detailed disposal facility design and

engineering, site selection process development with all the due consultation, broad based site screening would then have to be undertaken and eventually site selection, and both site and facility design would have to be reviewed and approved through the appropriate consultation and regulatory processes before site development and construction could begin.

Finally, we should note that in parallel with these disposal facility developments, Hydro and other nuclear utilities would need to be developing transportation systems.

So clearly, there will be a lot of government regulatory and public checks and balances before the concept assessment and review process that we are in right now, before a disposal facility can be realized.

We have provided considerable information on this issue through the interrogatory process, including response to 9.41.6, which was the used fuel plan document.

So in summary, Hydro is managing its used fuel safely and we can continue to do so for decades. So there is no urgency in developing a disposal facility, but nevertheless plans are in hand and technology is being developed in an orderly fashion, so

that eventually we should be able to dispose of this material.

Q. All right. Moving on to a different kind of radioactive waste. I understand that the operation and maintenance of nuclear plants results in other radioactive wastes which are not as radioactive as used fuel. How is Hydro presently managing these wastes?

A. Yes, that's right, there are a number of other radioactive materials that we generally refer to as low and intermediate level wastes.

The radioactivity of this material is typically less than 1 per cent of used fuel. We classify this waste as either type 1 or type 2 or type 3, depending on the level of radioactivity that it contains.

Type 1 waste is the least radioactive, mainly consisting of common items like paper, rags, mops, protective clothing and so on that become contaminated during the operation and routine maintenance and clean-up activities at our facilities. And generally speaking, these materials don't require shielding for handling purposes.

Some of this waste in fact is so low in activity that it can be reduced in volume through

compaction or incineration, for example, papers and cottons.

Type 2 waste, and this is somewhat more radioactive than type 1 one, it generally consists of filters and spent ion exchange resins used in various water purification systems in the stations, and shielding is generally required to handle this type of waste.

Type 3 waste, which is the most radioactive of the three categories, includes the more radioactive filters and ion exchange resins, as well as reactor components, for example, pressure tubes that have been removed from the reactor, and shielding is certainly required to handle this material.

Most of the radioactivity in low and intermediate level waste decays to background levels in a few hundred years, but some of it will remain active for longer periods. So even though this waste is much less radioactive than used fuel, it still needs to be carefully managed for a long period of time.

Most of these wastes are or will be transported from the individual reactor sites to our central waste management site or the radioactive waste operation site properly at the Bruce Complex.

Wastes from the retubing of reactors are

or they will be stored at the reactor site in special concrete containers that are approved by the AECB. This waste will be disposed of together with other wastes that will arise when we start decommissioning the reactors themselves.

Approximately 7,000 cubic metres of low and intermediate level waste is produced each year and sent to the Bruce site. By far the greatest proportion of this, in fact some 97 per cent on average is type 1 waste, the least radioactive. Type 3 waste usually accounts for less than 1 per cent of the annual volume of this material.

Total quantities over a five-year period from 1986 to 1990 were given by Panel 2 in Exhibit 1937, at page 19, for your information.

A breakdown for 1990 is given in my next overhead, which appears at page 57 of your overheard package.

This shows the annual, or at least for 1990, the volumes transported to the Bruce waste management site in each waste category, and the total quantity, as I said, is some 7,000 cubic metres.

In a typical year we make over 1,000 shipments of radioactive material without incident. This includes tritiated heavy water going to the

tritium removal facility at Darlington, as well as low and intermediate wastes going to the Bruce Complex.

All the shipments are carried out in accordance with the AECB and Transport Canada regulations.

My next overhead shows the facility that I have been talking about, that is the radioactive waste operation site at Bruce.

I should apologize for the quality of this overhead, it's not as good as I had hoped it would be. But perhaps it will be clearer in the hard copy you have got in the package.

I want to emphasize that this facility is anything but a landfill site. It's a highly engineered and monitored waste management facility that has been developed over the years to serve the needs our growing nuclear system.

It includes a range of processing and storage facilities specifically designed for different types and different forms of waste. For example, in the centre of the picture at what is labelled 2 is the waste volume reduction facility which includes compaction equipment, as well as a two-section incinerator system, one section for radioactive low level wastes, combustible wastes that is, and one

section for non-radioactive wastes.

This facility is currently able to reduce the volume of waste that it processes by about 60 per cent overall, and we are currently looking at the feasibility of upgrading this facility so that it would be able to reduce the volume of future wastes by some 90 per cent.

To the right of the waste volume reduction facility at label 5 is shown the storage building, low level radioactive waste storage building which is a pretty conventional building used for low level wastes and ash from the incinerator. The ash, incidentally, is stored in steel drums.

Shown below the waste volume reduction facility are a number of areas or stages of in-ground concrete structures referred to as trenches and tile holes which are used for low to median level wastes, and these are the shown at labels 1A, 1B, 3A, 3B and 3E.

And finally, at the lower left-hand corner of the picture is a row of above-ground structures, concrete structures referred to a quadricells, they contain four compartments, and these are used for special type 3 wastes such as bulk resin containers.

[12:21 p.m.]

The overall site here is serviced by both surface and subsurface drainage systems and effluent monitoring.

These waste management facilities at Bruce, plus available unused space at the site, are expected to provide sufficient storage capacity for our nuclear system needs until the year 2015 at least.

Our current radioactive waste management operations are similar to those used in other countries that produce low and intermediate level rad wastes. Some countries now are beginning to put disposal facilities into service for disposal of these kinds of wastes, for example, France, Sweden and the U.K.

Q. Mr. Johansen, what are Hydro's plans for longer-term management of these wastes and the future waste from decommissioning of existing nuclear facilities?

A. First of all, we have set a target as I think I alluded to before of reducing by some 50 per cent the volume of waste produced from our nuclear operations by the year 2000.

Exhibit 43 which was Ontario Hydro's presentation to ONCI, the Nuclear Cost Inquiry, describes our planned three-phased decommissioning

approach which is referred to as deferred dismantlement.

We have already developed conceptual plans for decommissioning each of our existing nuclear facilities based on this deferred approach and these plans have been registered with the AECB and a copy of the plan for Pickering, Bruce and Darlington was submitted in response to Interrogatory 9.6.8.

Our general plan following retirement of each station is to remove the used fuel and the heavy water from the reactors and to keep these materials in on-site storage until a disposal facility is available. This would be Phase 1 of the three-phased approach. Heavy water alternatively can be reused or sold, depending on future circumstances and needs.

The station structures and other radioactive materials would subsequently be maintained under surveillance for some 30 years, this would be Phase 2, prior to final dismantlement and disposal of materials and restoration of the site, which would be Phase 3.

The majority of the waste materials which would be produced from decommissioning of a nuclear facility, in fact over 90 per cent by volume, would not be radioactive and this is shown in Exhibit 43.

We are in the process of developing a plan for disposal of these wastes some time earlier than the target date I indicated for disposal of used fuel. The year 2015 is considered to be an achievable date, a target date for bringing a low and intermediate level waste disposal facility into service, compared to 2025 for used fuel. This 2015 target year will be well in advance of the time when the first of our nuclear stations is likely to be dismantled.

Finally, our planning approach for disposal of all low and intermediate level waste is described in more detail in our radioactive materials management overview document which we provided in response to Interrogatory 9.9.41.

Q. Thank you for that very thorough description of radioactive materials management.

For the final question, from an environmental protection viewpoint do you believe that Hydro's nuclear power plants can be operated safely to the end of their planned service lives?

A. Yes, I do. I believe that our plants are basically well designed, monitored and controlled. Maintenance programs are planned and feasibility studies and research is under way that could lead to further reductions in emissions and effluents

consistent with our ALARA policy and we have got plans and development programs under way for long-term management of radioactive materials.

So, yes, I do believe that our plants can operate to the end of their planned service lives.

Q. Thank you, Mr. Johansen.

MS. HARVIE: The next segment of evidence, Mr. Chairman, will be delivered by Mr. Penn and it deals with economics of Hydro's existing nuclear program.

Q. Mr. Penn, I understand you will be dealing with the current and expected cost levels associated with existing nuclear facilities including Darlington; is that correct?

MR. PENN: A. That's right. And I would like to do this by first explaining the various cost categories which contribute to the current costs of our nuclear generating supply; and, secondly, changes in these costs that might be expected during the planning period which include both increases and decreases.

Q. I take it that considerable evidence on these subjects is available to the Board?

A. Yes, substantial information is included in the following documents: Exhibit 3, which is of course the Demand/Supply Plan report, Exhibit 43,

the ONCI document prepared by Ontario Hydro, and this contains a comprehensive 1988 review of every aspect of nuclear costs of the current system and a potential multi-unit 4 by 881 megawatt CANDU option in the future.

While detailed changes have occurred since 1988 and more is now known about our operating stations, including Darlington, Exhibit 43 continues to be a major reference and a valuable resource of nuclear generation cost data and methodology for the entire nuclear lifecycle.

Third, Exhibit 44, Report to the Minister of Energy on ONCI; and, lastly, fourth, Ontario Hydro's answers to about 400 DSP interrogatories on costs.

Q. In order to provide some context for the discussion of costs, I understand you will be referring to the nuclear cost model used during the nuclear cost --

THE CHAIRMAN: Just so that we don't lose sight of this, an interrogatory isn't evidence until it's been referred to at the hearing.

MS. HARVIE: No, that's correct, Mr. Chairman.

Q. Could you describe further this nuclear cost model?

MR. PENN: A. Yes. This model is not a computer model, it's as shown on the easel immediately to your right and on the overhead and it's also referred to on page 59 of Exhibit 519, and it shows that the total costs are made up of three cost divisions called capital, operations, maintenance and administration, and fueling costs.

The model then sets out various cost components which are shown below which contribute to each of these three cost divisions.

Q. All right. I would like you then to take us across the boxes on the next row and giving us a bit of a description about what each covers, its importance with respect to the economics of the current nuclear system?

A. I would like to start with initial capital cost. That's the cost of our stations at the date the units go into service. The initial or original cost of a CANDU station consists of five subcomponents; namely, the dry cost, heavy water cost, initial fuel, commissioning, and staff training costs.

The dry costs are those associated with putting the completed structures in place and with many other important activities which determine the eventual success of the station. These activities included in

dry cost are: The approvals process for the project, including a hearing such as this, site characterization and preparation of the site, design engineering of the plant, construction of the plant, the purchase of material and equipment acquisition, project engineering during the building of the plant, supply contract supervision, project control of costs and schedule, quality engineering and assurance, and not least of all, the satisfaction of our regulatory authorities during the process of building the nuclear power station.

Beyond this dry costs also include the cost of community impact agreements. Of course, they also include the important components of interest accumulated on all expenditures prior to in-service and overhead costs. The dry costs are the largest single lifetime cost component in this cost model and amount to about 58 per cent of the total lifetime costs as shown in Interrogatory 9.2.118.

The second component of the initial capital cost is for the fill of the heavy water moderator and coolant systems. These costs include the heavy water production at the Bruce heavy water plant, its transportation to the station site and then the process of filling the reactors.

Moving down the list to the third component, half of the initial uranium fuel charge of the reactors is capitalized. The fourth component of initial capital cost is commissioning of the station. Commissioning is a process of checking that all of the systems and components perform their intended function and the resolution of any deficient performance. It also includes placing the station in-service.

Commissioning activities are very important. They ensure that all equipment is reliable and safe. The process trains future operating personnel and maintenance staff with hands-on experience.

The fifth and final component under initial capital is staff training. The capitalized training costs are about 1 per cent of the lifetime cost of a four-unit CANDU station. These expenditures are important to the smooth operation of the plant. The training costs including the acquisition of simulators which are like airplane simulators, are partly capitalized since the benefit is received by the future customers once the units are in-service.

The training includes that of authorized staff who assume control of the operating station, technicians, training for maintenance personnel,

support engineering staff and administrative staff. All of these initial capital costs that I have described are sunk costs; that is, money which has already been spent to build our existing stations. Except for the money being spent to complete Darlington, these costs won't now change. During the station's lifetime these costs are depreciated over the 40-year life of each generating station.

In total, the initial capital costs represent about 64 per cent of the total lifetime costs of a four-unit nuclear plant expressed on a present value basis.

In ONCI, Exhibit 43, there is further extensive information on this subject which I will update during my evidence.

Q. The next box to the right of initial capital is labelled LSFCR. Would you expand on that please, Mr. Penn?

A. Well as I mentioned in my introductory evidence, LSFCR or large scale fuel channel replacement or, in simple terms, retubing of CANDU reactors, means the replacement of the pressure tubes which are part of the coolant and contain the uranium fuel.

This process with which Hydro has

extensive experience entails a major repair to the heart of a CANDU reactor. It involves the removal of all pressure tubes throughout the reactor and replacement with new ones.

When the CANDU horizontal pressure tube concept was first committed in 1957, there was limited pressure tube technology. Pressure tubes in Pickering "A" were assumed to have an economic lifetime of 15 years, accordingly, all CANDU reactors have been designed to permit pressure tube replacement.

Subsequent reactors, as I noted earlier, have improved fuel channel design features which has led to expected 30 year lives for the pressure tubes in the "B" stations and in Darlington.

We have extensive knowledge on how to retube reactors safely. Our record is one of reducing time to do the job. Retubing costs are expected to represent about 2 per cent of the total lifetime cost for the "B" reactors and Darlington. Including the "A" reactors which have pressure tube lives between 12 and 25 years, this cost increases to about 4 per cent of the lifetime current nuclear system costs.

Q. All right. The next box is capital modifications. Would you describe that in further detail, please?

A. Capital modifications add improvement to the current nuclear assets and, therefore, provide benefits to future customers, that's why they are capitalized.

They involve replacement of a plant component that is identified as having a shorter life than the station. These costs are subject to annual reviews before the Ontario Energy Board. Modifications that cost less than $100,000 are expensed and are included in OM&A costs, which I will address later.

Examples of projects that are included in the planning estimates for capital modifications are as follows, and there are five categories.

First, repair projects of all kinds including repair to ensure equipment continues to meet regulatory needs.

Second, replacement of station components with shorter lives than the station life, for example, condensers and moderator heat exchangers.

Third - and a point that Mr. Johansen mentioned - addition of new facilities to accommodate low level waste.

Fourth, unidentified major contingencies - a subject I will talk about later - but an example is possible steam generator replacement.

And, finally, fifth, major new spare parts such as turbine rotors, generator rotor and generator status. Capital modifications are expected to contribute about 7 per cent of the power station's total lifetime costs.

Q. And decommissioning, what does that include?

A. Decommissioning involves the removal of the station structures and restoration of the site to the point where it can be used for other purposes. The procedures and methods are included in Interrogatory answers 9.7.25 and 9.6.8 and were mentioned by Mr. Johansen. These methods and costs have been reviewed by the Ontario Energy Board.

Chapter 25 of the ONCI document, Exhibit 43, also provides a comprehensive description of the methods to decommission CANDU nuclear plants and compares these methods and costs with those elsewhere in the world.

The recommended method is to remove the irradiated uranium fuel and heavy water from the reactors when the station is declared out of service. Mr. Johansen said then the station is secured for 30 years to allow reactor radiation to reduce by a factor of 1,000 and then we intend to use methods known today

to demolish the entire station.

In addition, it is an AECB's requirement in granting the Darlington operating licence that satisfactory evidence be provided for the plant's eventual decommissioning. This information is given in Interrogatory 9.7.25.

Our knowledge of how to safely remove highly active pressure tubes in retubing, our experience in assisting Atomic Energy of Canada Limited with their process of decommissioning the nuclear power demonstration plant and Douglas Point, and our involvement in other world decommissioning studies, such as the Shipping Port Reactor in the United States and our collaboration with the United Kingdom and Sweden gives us confidence in our decommissioning plans and their costs.

Decommissioning represents 0.2 per cent of total lifetime costs. This percentage is very small because costs are discounted over a very long period of time. Provisions to pay for our CANDU station's removal using an annuity method started in 1982 and now amounts to $314 million.

[12:40 p.m.]

Q. The next section is labelled OM&A and the first category under that section is called POMA.

Could you describe that, please, Mr. Penn.

A. POMA is an acronym for partial operations maintenance and administration costs, and it is related to the day-to-day costs of operating a CANDU nuclear station.

POMA is divided into two sub categories, which are direct OM&A and OM&A training.

On page 60 of Exhibit 519 we have described the type of things done in POMA and in training. These activities comprehensively describe how Hydro accounts for all the necessary actions to operate its reactors reliably and safely, including the continuous training of all staff during the station's life.

POMA is expected to represent about 20 per cent of the lifetime nuclear costs and is, of course, related to operating performance. Future OM&A over the balance of the planning period will be discussed later.

Q. The next category on page 59 of Exhibit 519 is labelled heavy water upkeep. What is involved in this activity?

A. Heavy water upkeep is also comprised of several components, actually three, and is shown on the next overhead and listed on page 61 of our Exhibit

519.

The three components are loss makeup, upgrading of isotopic concentration of recovered water, and tritium removal from station water to improve operating staff and public protection.

The CANDU design ensures that 95 per cent of the small amount of heavy water that escapes from the system is recovered, purified and reused.

The unrecovered portion, that is 5 per cent of that which escapes, is the loss makeup that's shown on this overhead. This portion is small in terms of cost over the nuclear station lifecycle.

The tritium removal facility at the Darlington site is now in operation and will contribute to reduced tritium exposure at all of our nuclear stations. It is, however, being used first initially to reduce exposures at Pickering nuclear generating station.

Heavy water upkeep in total is less than 1/2 per cent of the total lifetime costs.

Q. Going back once again to the nuclear cost model, the next heading is called fueling, and the first box beneath is called acquisition, what does that cover, Mr. Penn?

A. Fuel acquisition includes the cost of

uranium concentrate at the mines, the subsequent refining of the uranium, its conversion to oxide, and the manufacture of fuel bundles.

These procedures and processes are straightforward and representative of a mature industry.

The fuel bundles delivered to our stations are highly dependable.

Future fueling costs depend mainly on the source of uranium supply. At this time fuel acquisition is 6 per cent of the total lifetime costs of nuclear electricity generation.

Q. The next box is labelled disposal, what does that cover?

A. Mr. Johansen spoke about disposal of used fuel and it's further described comprehensively in Exhibit 43.

In addition, Interrogatory 9.41.6 describes Ontario Hydro's used fuel management plan. The conceptual design of the disposal facility has been developed by Atomic Energy of Canada Limited on behalf the federal government. The design is the result of more than 12 years of research and development which includes and underground laboratory in the Canadian Shield at Whiteshell, Manitoba, examination of major

natural radioactive sources known to have stablely existed for thousands of years, and extensive international collaboration.

As Mr. Johansen stated, the conceptual design of the repository calls for final disposal of the used fuel deep in plutonic rock in the Canadian Shield.

The cost estimate of our participation, that is Ontario Hydro's participation, in a detailed design and construction of this eventual facility is $3.4 five billion in 1992 dollars. Such a facility would be first in-service in 2025.

The estimated Hydro capital cost includes room for all used fuel from our current reactors to the end of their life. It also includes a further margin, that for assumption purposes is associated with the total discharged fuel from a future 4 by 881 megawatt station, so that our cost provisions are related to storing permanently five million fuel bundles.

The operating cost of this facility including transportation, immobilization at site and disposal of used fuel is estimated in 1992 dollars to be $1,575 per bundled.

A provision for this predicted eventuality has been collected since 1982. The cost to

the electricity consumer in 1992, that's this year, is 0.07 cents per kilowatthour. And the accrued provision to date including interest earned is $624 million. This matter is also subject to annual review by the Ontario Energy Board.

Disposal of used fuel represents just over 1 per cent of the total lifetime nuclear generation cost. The reason for this small percentage is the extensive time extending to the middle of the next century that these activities will occur. Provisions for this cost extend to 2033, which is the current date that Darlington would be declared out of service.

Q. And finally, under the fueling category the box inventory appears. Would you describe what that covers, please.

A. Inventory cost is the interest charged on the new fuel in storage at all our nuclear generating stations.

Sufficient fuel is kept at our stations to allow each reactor to operate at full power for six months. This policy is followed to ensure no interruption of electrical output due to loss of fuel production in any part of the fuel acquisition process. This inventory or interest cost in our inventory

contributes about 0.4 per cent of the total lifetime nuclear generation cost.

Q. Now, Mr. Penn, the percentage figures you have been giving I take it are your general expectations for stations of the kind now in Ontario Hydro's system. What is the basis for the 1 per cent of lifetime costs that you have been quoting?

A. They apply to large four unit integrated CANDU stations of the type we have on our system.

Page 62 of Exhibit 519 summarizes the figures I have quoted and updates the ONCI data to 1991 information.

The percentages could vary somewhat for our existing stations. For instance, I would expect the capital modifications and the retubing percentages to be somewhat higher for our "A" stations, but I think they provide a good general indication of the relative size of the various cost components involved.

Q. Well, looking across the top row of this overhead, I take it that within each of the three major cost divisions there are some items which are of particular interest with respect to the ongoing cost of operating the nuclear system. Would you identify what these are first in the capital section?

A. Well, looking at the way in which costs might vary for the balance of the planning period and starting with capital.

Initial capital cost, as I mentioned earlier, is sunk, and when looking at the future capital costs the main areas of interest are large scale fuel channel replacement or retubing that will be done in the future; capital modifications in the future, and the eventually decommissioning of our nuclear generating stations.

Q. I take it dealing with large scale fuel channel replacement, that this is an area where you have considerable experience in which to project future costs; is that correct?

A. Yes.

Retubing is required when the reactor pressure tubes reach the end of their service life. The pressure tubes during their life are limited by irradiation induced axial growth or by a failure process known has delayed hydride cracking. Hydro has extensive knowledge of both processes, including how to mitigate them to extend life for pressure tubes and when to replace the pressure tubes.

The life of the pressure tubes depends on the particular design of the fuel channel assemblies

which varies from Pickering type station to Bruce type station, and it also depends on the position of the supports or the garter springs that we have mentioned to you several times.

Prolonged contact, if these garter springs are not in their correct place, can prematurely end the life of the pressure tubes. Due to the fact that if there is prolonged contact of the hot pressure tube on the cold calandria tube and accompanied by tensile stress, then hydrogen or deuterium that's present will ingress to the zirconium tube and cause a delayed cracking process of the zirconium alloy.

The Hydro "A" stations are prone to this problem. But pressure tube lives are being extended by repositioning the garter springs.

The Hydro "B" nuclear stations have designs which avoid this problem. Their pressure tube lives are limited to 30 years by axial elongation.

Retubing has now been successfully carried out at Pickering Units 1, 2 and 3. Unit 4 is now being retubed, so that we feel we have a growing data base on which to be confident of future costs.

I should mention that the Unit 4 work is ahead of schedule and within cost estimates. In fact, taking the retubing program as a whole, it has been

successful in performing the work and within estimated costs.

Q. Could you outline Hydro's plan for retubing its reactors in the future?

A. The following table, which is shown on page 63 of Exhibit 519 shows our current plans.

On of the left-hand side of the table we list all 20 units in the present nuclear generating system. The next column in gives you the dates on which each of these units was declared in-service, and the third column provides the pressure tube life in years.

You will note that for Pickering 1 and 2, as Mr. King was mentioning this fateful day on August 3rd, 1983, when we had a pressure tube failure in Unit 2, caused a reduced life of the pressure tubes to 12 years. The lives of Pickering 3 and 4, when the reactors were shut down to retube, was 17 and 18 years respectively.

The life is also limited at Bruce 1 and 2 by axial elongation in the channel assembly design, but from there onwards lives extend up to 30 years, and the lives are chosen such that we will never be retubing more than one nuclear reactor at a given station at a particular time. We found by experience of retubing 1

and 2 of Pickering in parallel, that this is not an effective and efficient thing to do.

The next column provides the retubing outage in months. You will note a significant reduction from the first reactor, Pickering 2, through to Pickering 1 and there onwards.

The Bruce units, at Bruce "A", are of a different fuel channel design, and containment, as I noted in my introductory comments, square and of different size, and will cause us to have a slightly longer period than, for example, a continuing decline as shown by Pickering 3 and 4.

The actual proposed dates that we are planning to do the retubing of all these nuclear stations is shown in the fourth column, fifth column and the final column on the right-hand side shows the station retube costs, that includes removal and replacement, in 1992 dollars per kilowatt for each of the five stations.

You will note that the costs of Pickering B, that's the third row, is substantially lower, at $321 per kilowatt, than Pickering "A" at 477. And also, a comparison of Bruce "B" costs relative to Bruce "A" costs show a similar decline.

One of the main reasons is that we, in

retubing Pickering "A" and Bruce "A", have put in place facilities on site and tooling in order to carry out the repair which would be subsequently utilized in the "B" stations. Similarly, at Darlington we would have to set up an infrastructure there to carry out that work.

The next figure --

MS. HARVIE: Mr. Penn, perhaps this would be an appropriate time to break before we go on to the next overhead.

THE CHAIRMAN: We will break until 2:30 this afternoon.

THE REGISTRAR: Please come to order. This hearing will adjourn until 2:30.

---Luncheon recess at 1:00 p.m.

---On resuming at 2:35 p.m.

THE REGISTRAR: Please come to order. This hearing is again in session. Be seated, please.

THE CHAIRMAN: Ms. Harvie.

MS. HARVIE: Q. Mr. Penn, you were outlining Hydro's plans for retubing its reactors in the future and you dealt with the schedule and were beginning to speak to the costs in more detail when we took a break for lunch and I wonder if you could continue on starting with this overhead on page 64 of

Exhibit 519.

MR. PENN: A. Yes. This figure from Exhibit 519 provides the actual retubing costs in constant 1992 dollars per kilowatt of total capacity per annum until 1991 and that predicted for the balance of the planning period.

The variation in time reflects the increasing life of pressure tubes and the eventual overlapping and parallel activities of Pickering "B" and Bruce "B" stations. The figure shows that the retubing campaign at Pickering "A" is 10 years, that at Bruce "A" will be spread over a period of 17 years, and we will have activities at Pickering "B" and Bruce "B" for 12 years towards the end of the planning period.

This series of events explain the shape of the retubing cost variation over the planning period.

Q. And what has your experience been with the next area, capital modifications?

A. Capital modifications have been made to Ontario Hydro's operating nuclear stations to enhance public safety and improve station performance. Important modifications have occurred between 1976 and 1990 and the major ones are shown on page 65 of our exhibit.

I don't intend to discuss the detail of them, but I would like to talk about capital modification costs.

The cost of the nuclear program capital modifications between 1976 and 1991, whose activities I have just shown on the previous slide, per unit of totally installed capacity in dollars per kilowatt is shown on page 66 of Exhibit 519. The costs are provided in constant dollars.

Please remember that I previously defined capital modifications to include major repairs, replacements due to wear, system additions, major contingencies and significant new spares. Capital modifications, as you can see from this figure, are on average about $22 dollars kilowatt per year for the last 15 years. This is equivalent of slightly more than 1 per cent per year of the average initial capital cost of the current operating nuclear stations which, in 1991 dollars, is $2,025 per kilowatt installed, assuming a 4 per cent real interest rate.

Q. Will it be the older stations where the greatest expenditures will occur for capital modifications in the future?

A. Yes. Most capital modifications will be associated with Pickering "A" and Bruce "A"

stations. They will be completed during the planned and retube outages. Capital modifications on Pickering "B", Bruce "B" and Darlington are also included in the planning period estimates but they are smaller costs than those for the "A" stations.

Equipment replacement is based on continuous in-service inspection of the equipment and the cost is reviewed annually by the Ontario Energy Board. Rehabilitation categories include reliability and operating cost improvements, regulatory and environmental upgrades, and employee safety improvements.

Many individual equipment modifications are shown in the rehabilitation categories. Regulatory safety improvements involve actions such as the upgrade of the safety shutdown system at Pickering "A" that Mr. King alluded to.

The other categories, other initiative categories I mentioned include items such as MISA, that is Municipal Industrial Strategy for Abatement of Effluents, PCB elimination, environmental qualification of equipment for post-accident conditions, nuclear plant life assurance, and quality improvement initiatives.

Q. All right. Would you please

summarize the costs of capital modifications to the nuclear system in the future?

A. My overhead shown on page 67 of our exhibit shows costs in 1992 dollars for capital modifications that have already been carried out, those planned, and those forecast through to the year 2014.

In approximate terms the trend between 1976 and '91 was $22 per kilowatt per annum. From 1992 to 2001, it is forecast at $27 per kilowatt per annum including possible steam generator rehabilitation and 22 kilowatts per annum is forecast from 2001 onwards.

The expected costs between 1992 and 2002 are based on our 10-year business budget. As shown by the shaded area in the middle of the graph, there is potential for increased costs associated with the Bruce "A" steam generators, however, that situation is being investigated and no decision has yet been taken.

The costs represented by the shaded area allows, if we have to, the replacement of all eight steam generators in Bruce Unit 2 and the refurbishment of steam generators in Units 1, 3 and 4. The variation in time for the forecast period, that's beyond the ones I have been talking about, reflects the extensive modifications to Bruce "A". It also shows the range of our predictions for the balance of the planning period

to the year 2014.

Q. Mr. Penn, has Ontario Hydro performed economic or financial tests to ensure that these future capital modifications are economic?

A. Yes. Financial tests have compared the economics of needed modifications and retubing with replacement energy options. An example of that is shown on page 68 of Exhibit 519 and it shows the net present value of the future incremental costs of Bruce "A", including OM&A costs, fuel costs, capital modifications, and retubing to its retirement date, and that is the block shown to the right and headed $2.7 billion.

The net present value of the incremental costs of continuing Bruce "A" operation for its 40-year service life until 2018, including retubing, capital modifications, and other initiatives I described earlier, is $2.3 billion shown in the bottom half of that block diagram.

When steam generator refurbishment is included and if it becomes necessary to replace all eight steam generators in Bruce Unit 2 when it is retubed, the net present value increases to 2.71 billion.

Looking over to the left of the first

block diagram, the present value of replacing Bruce "A" station with existing fossil and new fossil generation, which would include combustion turbines and combined-cycle units, at the time that the Bruce "A" units are each retubed, is $4.5 billion. Thus, the advantage of refurbishing the Bruce "A" station is $1.79 billion net present value when compared with replacement fossil capacity and energy, taking all costs into account.

The detail of these types of comparisons can be provided by Panel 10.

At this time only one of the eight steam generators on Bruce Unit 2 indicate concerns to us warranting consideration for future replacement.

Continuing inspections indicate that the steam generators on Bruce Units 1, 3 and 4 can be cleaned and refurbished, thus, the net present value shown on figure 68 is considered conservative.

If we took an extreme scenario where we assume that all 32 steam generators in the Bruce "A" station in every unit were replaced when each of those units were retubed, the advantage of refurbishing the station would become $1.63 billion relative to fossil energy and capacity replacement.

Q. Thank you, Mr. Penn. The next box on

the overhead, being page 62 of Exhibit 519 is -- oh, yes, is decommissioning. What costs have been allowed for that purpose?

A. Current cost estimates for decommissioning our nuclear plants are unchanged from those given in Exhibit 43 which is the ONCI document, except for escalation from 1988 dollars to 1992 dollars.

As mentioned before, decommissioning represents 0.2 per cent of the 40-year lifetime generation of a CANDU station, taking into account the extreme length of time into the future that such an activity would occur.

The 1992 cost estimates for decommissioning our nuclear stations are $1.11 billion for both Pickering "A" and "B"; $1.27 billion for both Bruce "A" and Bruce "B"; and $960 million for Darlington. The provisions collected to do this so far amount, with interest, to $314 million, that's 1992 dollars.

Allowing for the 30-year stop and store period, our present plans call for completing the decommissioning of our nuclear stations, starting with Pickering "A", by the year 2060 and ending with Darlington in the year 2073.

Q. All right. Turning now to the OM&A area, could you give the panel a general picture of how those costs attract over time?

A. Yes, and here we are really talking about partial operations, maintenance and administration costs. We don't expect any significant increase in the cost of heavy water upkeep.

If we turn to the next page, to page 69, this figure shows for the existing nuclear program how the OM&A unit capacity costs have changed over the period 1974 to 1991 in 92 dollars per kilowatt.

During the period 1974 to 1982, costs rose slightly on a constant dollar basis. Following this period when we had surplus generation and also economic conditions led to budget restraints which cut into OM&A resources, you can note that the OM&A cost declined, and it was over that period that the performance of our nuclear stations tended to decline also.

The resulting backlogs of preventative maintenance, repairs of minor system deficiencies, and installation of testing of modifications contributed to the decline in our nuclear performance.

Our cost analysis reported in ONCI in 1988 recognized that direct OM&A costs needed to

increase starting in '88 to respond to declining "A" station capability factors.

OM&A resources, mainly staff, were increased starting in that year. The rate of increase of OM&A costs over the past few years has been high to restore performance to an appropriate level. Nevertheless, our current OM&A cost level at the end of 1991 is still about 50 per cent of the United States average for light water reactors.

Q. You see the OM&A costs remaining at this higher level in the future?

A. Yes, I do. It's clear that adequate operations support, both at the stations and by engineering science and administrative staff at head office and within Canadian industry, is most important to achieve high capability and, therefore, low system costs.

The figure on page 70 consolidates actual OM&A costs in the '74 to '91 period with those budgeted over the next 10 years and predicted up to 2014 in '92 dollars per kilowatt.

In the forecast period, that's beyond to the right-hand side at the vertical dotted line, the initial drop is related to the capacity of Darlington coming on line, therefore, increasing the kilowatt

capacity. From 1993 onwards the projected OM&A is shown as a diverging band. This band is based on ONCI assumptions for 80 per cent confidence limits of the future OM&A cost to 2014.

Q. All right. Turning now to the fueling costs, could you give a general picture of how these costs attract over time as well?

A. The fueling costs are shown on the next overhead, page 71 of our exhibit. This shows the fueling cost variation in cents per kilowatthour of energy delivered during the period 1974 to the end of 1991.

The actual cost experience between 1974 and 1986 increased by nearly a factor of three, however, the costs since the mid-80s have moderated. This cost variation is mainly due to escalating uranium ore prices in the Ontario/Elliot Lake contracts and the subsequent influence of lower cost supplies from Saskatchewan.

Q. Overall then, what does Ontario Hydro see happening to its nuclear fueling costs in the future?

A. Our fueling unit energy costs in constant cents per kilowatthour are summarized on page 72 for the period 1974 to 2014. By 1997 it is expected

that the average cost in constant dollars will decrease to half its current value. After 1997 the price is expected to increase slightly until the year 2009 and then remain relatively constant.

The reason for the expected cost decrease is that, as announced on April the 29th, 1991, for the Denison Mines contract, and on June the 17th, 1991 for the Rio Algom contract, Hydro will be moving from these high priced contracts to lower cost uranium.

Much of the new supply is expected to come from Saskatchewan. All grades in Saskatchewan are on an average between 2 and 3 weight per cent of uranium in ore contained, whereas the ore grades in Ontario are typically 0.05 per cent to 0.1 uranium by weight, therefore, recovery costs are substantially lower for Saskatchewan ores.

I would like to note that the uranium reserves, both proven and probable in Saskatchewan, are greater than 400,000 tonnes compared to Hydro's current requirements of 1,700 tonnes per year.

Q. Mr. Penn, one of the components of the fueling cost is the future disposal of used nuclear fuel including its transportation and final repository costs. Describe what happens with that fuel currently and its eventual disposal costs?

[2:55 p.m.]

A. Used fuel, as you have heard, is currently stored safely at Hydro's generating stations under water. We know it can be stored under water without concern for at least 50 years. The storage cost is charged to OM&A.

As Mr. Johansen stated, we have also developed dry fuel storage in special concrete containers and this method is used at Douglas Point and Point Lepreau. We intend to use that method at Pickering.

Extensive R&D indicates that this method is safe for one years and the containers are designed, as you have heard before lunch, for transportation which will reduce final used fuel disposal costs.

It is expected that these engineered concrete containers will be used at all Ontario Hydro sites in the future. The costs of storage in these containers is $11,000 per tonne of uranium, compared with $12,000 per tonne of uranium for water pools.

As stated earlier we plan to dispose of our used fuel in a deep repository, built in plutonic granitic rock within the Canadian Shield. As Mr. Johansen described, the technology for doing this is the subject of a federal environmental assessment and

review process which is under way.

The estimated cost of used fuel disposal including all activities necessary to place it securely in a repository is $1,575 per fuel bundle in 1992 dollars. As I mentioned earlier in my evidence, Hydro's cost for acquiring the repository is 3.45 billion in '92 dollars.

Q. And again, I take it that provision for these future costs is made in the current rates?

A. Yes, just as with decommissioning costs, the OEB reviews this matter in relation to provides is being made in current rates. Since 1982 we have a crude $624 million for this purpose.

Provisions for used fuel disposal will continue on an annual basis until all of our nuclear stations are declared out of service, and they will be determined, that is the provisions will be determined, by the nuclear fuel usage in that year.

Another provision we plan to make, starting in 1993 is for the disposal of low and intermediate radioactive waste currently stored at the Bruce waste management site which was described by Mr. Johansen. The expected cost of low and intermediate active waste disposal is $215 million in '91 dollars.

The 1993 provision for this disposal

facility is $14 million, and is subject this year to an OEB review.

Q. Mr. Penn, the last component in the costs model, referring back again to page 62 of Exhibit 519, is the carrying charge and the fuel inventory held at the stations. Can we expect any significant change in this cost in the future?

A. There will be no significant change in the inventory interest carrying charge. It will of course decline slightly as we reduce our Elliot Lake inventory, but it is a small portion of the total generation cost.

Q. All right. I would like you now to conclude by summarizing your overall generation cost trend for the current nuclear system. You have explained the reasons why various cost components could be expected to increase or reduce. In a nutshell I would like you explain what is the overall picture on costs.

A. The overall picture of our nuclear generating costs both in the past and to the end of the planning period is shown on page 73, and is provided on the overhead.

This graph provides the accounting unit energy cost for the total existing nuclear program,

also referred to as total unit energy cost.

It also provides the variation of the main cost divisions that I defined earlier; namely, sunk capital, capital modifications including retubing, fueling, and OM&A for our present nuclear program.

Actual costs are provided for the period 1974 to 1991, and forecast costs are provided for the balance of the planning period to 2014.

These costs are provided in terms of cents per kilowatthour and are in constant 1992 dollars. In this way we avoid the complication of inflation and we can make comparisons in terms of the value of money today.

The capital costs shown in black and labelled sunk capital are the dominant component for most of the time. They relate to the depreciation and financing charges associated with paying for the stations, and the capital modifications including retubing that have already been placed in-service. They also include the annual provision for decommissioning our station.

In the forecast period, to the right of the vertical dotted line, we have separated two categories of capital cost. The first category shown in the upper part of the graph is the sunk capital

depreciation and financing charges of all assets in our stations, including Darlington.

The second category is future capital charges associated with the capital modifications, rehabilitation and retubing which we plan and expect to do between 1992 and 2014.

These are incremental capital costs to the present sunk costs and are shown above the fueling costs in the graph.

Q. All right. Would you explain why that graph shows an irregular shape for the unit energy costs and an obviously decreasing capital cost component of the unit capital cost?

A. Yes, I would like to explain the irregular shape of the unit energy cost variation and increasing capital component in that period in comparison to the much smoother variation in the forecast period.

Looking at the left-hand side of the graph there are there distinction increases starting in 1976, 1983 and 1990. These increases relate to the sequential in-service declaration of the Bruce "A", Pickering "B" and Bruce "B", and Darlington units.

The fluctuation in costs is also influenced by the average interest rate on the mix of

outstanding bonds of different maturities associated with Hydro's debt.

These financing charges are apportioned according to the book value of Hydro's total assets.

Finally, annual capacity factor variations influence cost variations. After all units at Darlington are declared in-service and the existing nuclear program is complete, there will be no new initial capital depreciation costs.

Q. All right. You have covered the past. Could you conclude by summarizing the main issues that are expected to determine future energy costs of the existing nuclear program?

A. During the next three years the trend will be increasing unit energy costs. Thereafter, costs are expected to decline in constant dollar terms for the balance of the planning period. The decline will equal about 35 per cent of today's costs.

The total unit energy cost will reach a peak in 1994 when all of our 20 nuclear units are expected to have been declared in-service and all are being depreciated at a full year's cost.

The peak level depends on the total initial capital cost of the Darlington station. The present expected cost in dollars of the year spent for

Darlington is $13.8 billion including accrued interest costs of $5.8 billion.

This cost is based on the assumption that our current plans to replace the 5 vane impellers with 7 vane impellers that Mr. Daly spoke of in the primary heat transport pumps will enable full power without further modifications to the units.

There is understanding that this fix will be successful and we will know whether we are successful by this July. But if additional modifications are required to the heat transport system piping, the time to reach maximum unit energy cost could extend to the 1994/95 period.

The dominant reason for the declining costs over the balance of the period is the significant reduction in sunk cost depreciation and financing charges as we pay off our mortgage on our nuclear assets.

The continuing economy of our existing nuclear program is related to the future incremental costs of OM&A, fueling and capital modifications, including retubing.

These costs are bound by the envelope of the future capital costs as shown on the graph, and which I have previously referred to as the second

category of capital costs.

The trend of these incremental costs is expected, as you can see, to be slightly upwards in terms of constant 1992 dollars.

Finally, in terms of cost to our customers, the graph before you represents our expectation of the cost of electricity from the existing nuclear system over the balance of the planning period.

Q. Thank you. Turning to the last area Mr. Penn, I take it that Ontario Hydro has undertaken what the update document refers to as a preliminary of review of nuclear options.

A. Yes, we have, and there were three reasons for this. First, the Demand/Supply Plan requested nuclear approvals based on a 4 by 881 megawatt CANDUs taking advantage of their low levelized unit energy costs for this option for base load supply.

However, the 4 by 881 megawatt CANDU has the longest project lead schedule of all nuclear alternatives and is relatively inflexible to changing load requirements. On the other hand, single unit as opposed to multi-unit nuclear stations offer potential for added planning flexibility in future uncertain times. They can be sequentially committed at any given

site.

The second reason that we undertook this preliminary view of nuclear options is that the moratorium on nuclear project studies meant that the in-service dates for 4 by 881 facilities were clearly extended well beyond this in-service date set out in the DSP for the earliest nuclear stations.

Third, our start up problems at Darlington were troublesome, so we wanted to review options with shorter lead times and reduced investment risk which might provide increased flexibility for our planners, albeit with a higher levelized unit energy cost in most cases.

Q. Having started the review on that basis, were there other factors that came into play?

A. Yes, our review started by focusing on options which seemed reasonable to consider if we assumed the nuclear moratorium was lifted in mid-1993. These included proven CANDUs of various types: The 4 by 881, a four-unit station of the Pickering "B" type, and the CANDU 6 reactor.

We estimated the earliest in-service date for a 4 by 881 station as 2005, and for a CANDU 6 of 2003, as shown under the heading proven options on the table that's now on the screen and is listed on page 74

of our exhibit.

Q. I take it from this table that you also considered light water reactors?

A. Yes. Although we really focused on the more current work on evolutionary designs such as the advanced light water, ALWR designs. I should say that the advanced light water designs are either being built or planned in France, Finland, England, Korea, Japan and Taiwan, and there is an active development program in the United States as well.

As shown on our exhibit, page 74, we included for illustrative purposes a design, ALWR design called System 80 Plus and I will be describing the various designs in a moment.

Q. I take it there are also CANDU evolutionary designs?

A. Yes, there are. These include designs such as the CANDU 3 and the CANDU 9.

Q. Did you look at any other designs?

A. Yes. We considered what are known as passive safety designs, but initially did not focus on them because from a practical viewpoint, they were not expected to be in-service and proven until well toward the end of the planning period. However, with the Update DSP calling for base load supply in about 2010,

these could become relevant, so I have added some information on these passive designs in my evidence. But I emphasize that although there is considerable work being done on various evolutionary and passive designs, none have been fully designed, licenced in the country of origin or built.

Q. I would ask you now, Mr. Penn, to explain some of the terminology. What is meant by evolutionary and by passive design?

A. Future designs of nuclear power stations targeted for operation at the turn of the century and continuing into the 21st century are either classed as evolutionary or passive safety design.

Evolutionary designs build on the knowledge of current proven plants, but also incorporate improved safety features and station layout arrangement. They incorporate designs to allow modulized construction if factories and on the construction site. This approach permits shorter schedules, that is lead time for in-service, lower capital costs and simpler operation which enhances safety provided by the improved safety concepts.

The intention of all world vendors on evolutionary designs whether CANDU or light water reactors is to standardize the concepts so that

subsequent plants will be the same and the learning curve will result in declining costs and schedule with improved performance reliability.

On the other hand, passive safety designs are new concepts which adopt the fundamental aspects of the evolutionary design but have safety systems which heavily rely on the natural laws of physics as opposed to use of applied energy to cause safety systems to operate.

The passive safety design concepts of future nuclear plants go further than the evolutionary designs in their quest for simplification.

World-wide there are different views on the advantages of evolutionary and passive safety designs. It is felt that the evolutionary designs do not require prototype demonstration since they are based on proven principles. On the other hand, it is generally recognized that the passive designs do need to undergo large scale laboratory testing and possibly prototype demonstration. There is, however, unanimous agreement that both designs offer advantages over current operating stations in terms of planning flexibility, costs and lead time to in-service.

Q. Going back to the different designs then, what improvements are reflected in the cost and

schedules associated with future multi-unit CANDU station designs?

A. Talking first about Hydro multi-unit CANDU station designs, we reviewed two types of Hydro multi-unit stations, an improved Darlington station with a total capacity of 3,524 megawatts, and an improved Pickering "B" station whose capacity is 264 megawatts. I described their basic design features earlier in my introductory evidence.

I will briefly comment on the improvements to these designs resulting from our schedule and cost reduction studies that Hydro carried out from 1986 to 1990.

The improvements are reported in Exhibit 43, that is ONCI, until 1988, and in Interrogatory 9.2.118, from 1988 to 1990.

This work was the basis for the selection in 1989 of the 4 by 881 megawatt station design called CANDU A in the original Demand/Supply Plan.

The improvements relate to advanced engineering prior to construction, numerous constructability studies, the use of standardization and repeatability of proven systems and equipment, and modular construction where possible.

[3:17 p.m.]

Other key areas of improvement were the use of refined seismic analysis, distributed control systems, fibreoptic use, selective concrete embedded parts, and Hydro's development of a three-dimensional electronic drafting and management database system.

These improvements and many more related to lessons learned from the French, Japanese and Americans and led to improved future plant construction times.

Nevertheless, planning flexibility of this option in uncertain times is low. Darlington costs have risen to high values in part because of five scheduled interruptions during construction. These interruptions were very costly. The levelized unit energy cost of multi-unit stations is favourable compared with single unit stations if constructed without interruptions.

Other important characteristics such as commercial availability, safety and environmental protection offered by Hydro designed future multi-unit stations are regarded to be high.

Q. What other future CANDU developments are there that might be suitable for potential in-service around the year 2010?

A. We have consulted with Atomic Energy

of Canada Limited and have a confident understanding of the characteristic of these alternative CANDU designs including the proven CANDU 6 and the evolutionary CANDU 3 and 9, which are in the design stage. I will describe each of these designs, their attributes and specific lead times and costs.

First, the CANDU 6. It's a single 670 megawatt unit concept with positive pressure containment with no vacuum building. The stand alone units can be committed one at a time to permit increased flexibility and reduced financial risk. Multiple units can be built on a common site to gain savings.

The CANDU 6 is a proven design with over 36 reactor years of experience in New Brunswick, Quebec, Korea and Argentina. CANDU 6 units have demonstrated reliable performance and have achieved capability factors of 89 per cent on average over the last five years.

Point Lepreau in New Brunswick demonstrated a capacity factor of 97.7 per cent during '91 and with a lifetime performance record of 91.1 per cent, it is a co-leader of all world reactors which have been operating over eight years.

CANDU 6 has demonstrated an excellent

safety record. It offers improved planning flexibility in uncertain times to us compared with the 4 by 881 CANDU because of its smaller unit size and shorter lead time.

On the next overhead, page 78 of the exhibit, this shows the critical path lead time of a CANDU 6 station for in-service in the year 2010. The start of the critical path activities is late 1999 and that is the start date for preparing an environmental assessment document which would be ready for submission in spring 2001.

You'll note that in preparing this schedule, I have taken the liberty of suggesting that an approval through a hearing process could be accomplished in 24 months which would bring us to an approval of the concept, if that was the case, in spring to summer 2003, the critical path would follow to gain Atomic Energy Control Board's approval to construct, followed by Ontario Hydro Board of Director approval to proceed with acquisition and order-in-council to follow. That would signal the order of the major equipment being the reactor calandria vessel.

There would be a period of 16 months, given that this particular example is taken to be an

existing site, to clear the site and perform the excavation. The critical path then follows from first concrete for a 59-month construction period to give in-service at the beginning of 2010.

I have just shown you this as an illustration of the nature of the critical path lead times that we have in investigated.

I would like now to move and say a few words about the evolutionary CANDU 3.

It's a single 450 megawatt unit of evolutionary design based on proven technology. The detailed design is currently 80 per cent complete. Design features like the CANDU 6 include high pressure containment with no vacuum building but does include extensive modular construction techniques to reduce construction time.

This design is being reviewed by the Atomic Energy Control Board for upfront licensing of construction and operation.

Modular design is predicted to yield improved performance over proven CANDU options largely because of the ease of maintainability. A lifetime capability factor of 85 per cent or greater is expected.

Lead time is expected to be shorter than

for proven CANDU options, but greater uncertainty exists regarding its untried concepts. The stand alone nature of the station allows capital commitment risk to be reduced by committing one unit at a time closer to the need dates.

I would now like to say a few words about CANDU 9. It is also a single but this time 880 megawatt unit design. The design is evolutionary and will incorporate features of both the CANDU 3 and the Bruce Darlington type units. Indeed it is based upon the Darlington style reactor.

It features high pressure containment with no vacuum building and modular construction techniques. Detailed engineering has recently started. The design, like CANDU 3, includes improved station layout to enhance safety and longer life pressure tubes which are easier to replace, however, there are time and cost risks compared to proven CANDU options for this design.

Lead time is expected to be shorter than for proven CANDU options, but uncertainty exists because the design is at the conceptual stage. The stand alone nature of the station allows capital commitment risk to be reduced by committing one unit at a time.

The design has to be approved by the Atomic Energy Control Board. The CANDU 9 is predicted to yield higher performance largely because of ease of maintainability. A lifetime capability factor of 85 per cent is expected.

I would now like to end this short discussion on the CANDU options before I move to the light water reactor options by showing a series of overheads shown on pages 75, 76 and 77 which show the lead times and the cost ranges for various CANDU nuclear options as a result of variations in their size, numbers of units that would be committed on a particular site, the site location where this may occur, either being a new site or an existing owned site by Hydro, and the level of contingency that Hydro has seen fit to put on the uncertainty of the costs provided to us.

The first figure on page 79 shows the range -- I'm sorry, excuse me, my package is not in order, so...

Q. Page 75.

A. Referring to page 75, thank you. The lead time shown on page 75 at the top, first of all, for the proven multi-unit Hydro design. The lower limit or the shortest lead time is that associated with

building a Pickering style four-unit station on an existing site. The longest lead time for a multi-unit station at 180 months is that associated with building a 4 by 881 megawatt station on a new site.

Similarly, information on lead time is given for the CANDU 6 in the middle and the CANDU 3 and 9 below. Again, for the CANDU 6, the 123 months from start of putting together the environmental assessment document to in-service, and given the assumptions that you saw earlier on the critical path diagram, would be 123 months at an existing site, 168 months at a new site.

Moving to page 76 this provides a summary of the range of initial capital costs that Hydro would expect for an Ontario Hydro multi-unit station either 4 by 516 megawatts or 4 by 881 megawatts at, for the lower limit, and for a 4 by 881 megawatt station at an existing site.

The $2,700 per kilowatt would represent the cost of a 4 by 516 megawatt station at a new site.

Moving down, the CANDU single unit, the lowest capital cost of $2,750 per kilowatt is that associated with a single CANDU 9 station at an existing site, and $4,000 per kilowatt for a CANDU 3 at a new site.

If, on the other hand, Hydro were to commit 12 months apart four separate CANDU units of either of the CANDU 3, 6, 9 variety, then the lower limit of cost of $2,000 dollars per kilowatt would relate to four CANDU 9s on an existing site, or $2,800 per kilowatt for four CANDU 3s on a new site.

And moving to page 77 this provides a similar summary of levelized unit energy costs in 1991 cents per kilowatthour and follows along the same lines of description that I gave to you on the capital costs in dollars per kilowatt.

So, therefore, as an example, CANDU 9 with four units at an existing site has the lowest initial capital cost and the lowest levelized unit energy cost, and CANDU 3 at an existing site has the shortest lead time of 112 months and a construction duration of only 38 months but has the highest cost.

MS. HARVIE: Mr. Chairman, as it's just past 3:30 maybe we should take our break now. My prediction, although I've been quite inaccurate so far, is that we are going to be another 15 minutes in chief.

THE CHAIRMAN: Would you rather finish and then we will take a break?

MS. HARVIE: Yes.

THE CHAIRMAN: Why don't we do that.

MS. HARVIE: All right.

Q. All right. Mr. Penn, would you turn to nuclear option developments outside Canada. I understand these are the light water reactors that you referred to earlier?

MR. PENN: A. Advanced light water reactor designs, known for short as ALWR, are expected to make the nuclear option more attractive. France, Finland, U.K. Korea, Japan and the United States have plans to build or are building new evolutionary light water reactor designs.

The U.S. ALWR development programs are utility driven and have participation and sponsorship of numerous international utility companies and close cooperation and support from the United States Department of Energy.

The U.S. ALWR program was established under the Nuclear Power Oversight Committee known as NPOC. NPOC, whose members include chief executive officers of major utilities and industry, has taken the lead in bringing utilities, designers and industry support organizations together to define policies, design features and operational aspects of a new generation of nuclear reactors in the United States.

Two evolutionary designs proposed by

General Electric and ABB Combustion Engineering, known as ABWR and System 80 Plus, and two passive designs proposed by Westinghouse and General Electric called AP 600 and Simplified Volume Order Reactor are currently undergoing United States nuclear regulatory review and approval.

At this stage none of the advanced LWR designs have been licensed in the United States. The passive safety designs are expected to be ready for ordering in the late 1990s. These will be 600 megawatt nuclear plants with greatly simplified safety systems.

The United States' proposed one-step licensing process, which enables early site permit, standard design certification, and combined construction permit and operating license is an important concept for the future of nuclear power in the United States. This regulatory area still requires great efforts before it becomes a reality, but progress is being made.

The United Kingdom LWR development program and studies are focused on the advanced size well pressurized water reactor, however, cost estimates for these plants are currently high.

The European Economic Community nuclear program, including France and Germany, is developing a

unified pressurized water reactor evolutionary design using the best of their proven designs. This program has high promise given the success of the French nuclear program.

Initiatives in Sweden involve the evolutionary BWR 90, boiling water for the 90s, and passive safety design called PIUS. BWR 90 has been tendered to Finland where it is found licensable. The design of PIUS has entered the early design stage and has support from Italy but the licensing reviews have not yet started.

Japan has committed to two advance boiling water reactors in December, 1991, ahead of others, and is expected to take the lead on ordering an evolutionary advanced pressurized water reactors in late 1992.

Japan is doing research on passive safety systems but is not expected to commit to them prior to 2010 in-service.

I would now like to refer to two overheads given on pages 79 and 80 of our Exhibit 519. These provide consecutive lead times for the designs I've discussed and estimated capital costs.

On page 79 we provide our view of the lead times using similar assumptions to those including

an approval period through a public hearing of some two years following the preparation of an environmental assessment document. In this case, since these are advanced light water reactors where Hydro has less knowledge of CANDUs, we have allowed longer periods of time to prepare the environmental assessment document.

It shows for the evolutionary advanced light water reactors that have capacities ranging from a 1,010 megawatts to 1,356 megawatts a range which has a lower limit on lead time of 132 months, which would be for a plant at an existingly owned Ontario Hydro site, or as long as 177 months if it was at a site, a new site not owned by Hydro currently.

[3:40 p.m.]

Similarly, data is given for the advance light water reactor passive design below.

Moving over to page 80 we provided, based upon information given to us by vendors - and I must comment that in these times where people are tendering, this is commercially restricted information, at least the base information is - we have included Hydro added costs in providing these numbers.

The total initial capital cost therefore that we estimate currently to Ontario Hydro of building one to four ALWR evolutionary designs would range from

$2,150 to $4,150 per kilowatt. Here again, the lower limit would be for the building of four such units on an existing site.

The higher cost of over $4,000 per kilowatt would be for building one of these particular alternative units on a new site.

Similar information is given below for one of four passive ALWRs.

The contingencies that we have assumed in projecting these costs in our preliminary nuclear options review ranges from 25 to 30 per cent of the vendor's target cost.

Q. Okay. Mr. Penn, you reviewed the CANDU and light water reactor future nuclear options separately. Would you bring them together now and summarize their respective characteristics and estimated capital and lifetime costs.

A. For the future it is likely that there will be a choice of single nuclear unit size ranging from 450 to 1,400 megawatts. We could also adopt multi-unit stations or commit sequentially one, two, three or four single units on a site, any site, that in fact would give us a range of capacity varying from as low as 900 megawatts to 5,600 megawatts. This is a wide range of choice and represents considerable

flexibility.

The characteristics of the various designs are summarized in a very precise way and shown on page 81 of Exhibit 519. This chart lists the options and provides the expected lifetime performance, planning flexibility, commercial feasibility, safety level, environmental performance and lead time from concept to in-service. It notes the impact of committing to non-Canadian designs.

On the following two pages, page 82 and 83 of Exhibit 519, it provides a comparison of levelized unit energy costs for all options over the entire generation cycle represented by the lifetime cost models for in-service in 2010. They give the levelized unit energy costs for single and four-unit stations on the same site.

So if I may interpret what they mean on page 82, it summarizes for both CANDUs, evolutionary, and evolutionary ALWRs and passive ALWRs, for single units the range of levelized unit energy costs between building on an existing Hydro site and a new site somewhere in the province.

Similarly, on page 83 it provides Ontario Hydro's estimate, our estimate, for the levelized unit energy cost of four single unit stations of either

evolutionary CANDU or ALWR evolutionary and passive compared with Ontario Hydro's multi-unit 4 by 516 or 4 by 881 megawatt station.

There is one thing, Mr. Chairman, that I want to bring to your attention, that on page 81 - and I only noticed this when I was reviewing this material again last night - I have a typographical error. If you look down the first column against BWR 90, that is the eighth entry down, a design from Sweden, and move over to the last but one column on the right-hand side under levelized unit energy cost, the range should be 6.0 to 7.5. And, indeed, on the figure that's next on page 82, that number is correct, that 7.5.

I'm sorry for that, sir.

These costs that I have just reviewed include contingencies of 15 per cent on proven designs, 20 to 25 per cent on evolutionary designs, and 30 per cent on passive designs. These costs represent Hydro's assessment based on its preliminary review and include allowances for Hydro's costs and those necessary to meet Canadian regulations, specifically with regard to offshore designs.

In summary, this cost information which embraces both existing and new nuclear site locations and singularly are multi-unit stations of different

capacity, shows that proven and evolutionary CANDUs are competitive with future light water reactors. More importantly, future costs and lead times are reduced from those of past stations in real and actual terms.

Q. Finally, Mr. Penn, why can Hydro expect either CANDUs or light water nuclear reactor options to be available for in-service around 2010, if needed?

A. Well, in summary, there five reasons in my view why Ontario Hydro can expect nuclear options to be available for in-service in 2010, if needed. And they are: Firstly, significant Canadian industrial effort will be required to maintain and improve the performance of Hydro's current nuclear stations. This activity will consolidate the CANDU proven options and assist in export orders by Atomic Energy of Canada.

Secondly, Canadian industry is investing significant effort and funds in the development of evolutionary CANDU single unit stations. Enhancement of current CANDU passive safety systems are being developed which are innovative and will add to public safety assurance.

Third, extensive efforts and infrastructure support throughout the developed countries is occurring in the development of light

water reactors. These efforts are being driven by the major world activities and regulatory authorities are actively assessing designs for one-step licensing. Several world utilities are currently ordering or evaluating tenders for advance reactor designs which represent an ongoing commitment to the nuclear electricity option.

Fourth, both CANDU and light water systems under development are simplified designs, we believe will be easier to construct and to operate and maintain, and they employ an evolution of proven safety concepts.

And finally, nuclear plant studies in the U.S., Europe, Japan and Canada are concentrating on reduced lead times, lower costs, and in particular, assured regulatory licensing and public approval.

MS. HARVIE: That concludes our evidence in chief, Mr. Chairman.

THE CHAIRMAN: Thank you, Ms. Harvie.

We will take an adjournment now. The panel are going to have some questions of this panel. I don't know whether we will be able to reach, Mr. Mattson, I don't know if we will be able to reach your motion this afternoon or not. I am not sure we will be able to do that.

MS. McCLENAGHAN: Tomorrow is fine as well. That is fine.

MR. MATTSON: Mr. Chairman, this is Ms. McClenaghan.

THE CHAIRMAN: Yes, that's right, I didn't see her. That will be fine.

We will adjourn now for 10 minutes.

THE REGISTRAR: Please come to order. The hearing will take a 15-minute recess.

---Recess at 3:50 p.m.

---On resuming at 4:10 p.m.

THE REGISTRAR: Please come to order. This hearing is again in session. Please be seated.

DR. CONNELL: Panel, I would like to ask a few basic questions about technology, just to clear up some of the issues that you covered but weren't entirely transparent to me.

If I could just begin with the reactor itself. As I understand it, the fuel is inside the pressure tube, with D2O coolant flowing through the pressure tube. So far...

MR. PENN: That's correct, sir.

DR. CONNELL: Right. And outside the pressure tube there is an annular space--

MR. PENN: Yes.

THE CHAIRMAN: --where you have the springs. That's filled with gas?

MR. PENN: Carbon dioxide.

DR. CONNELL: Carbon dioxide, thank you. And outside the calandria tube?

MR. PENN: Yes.

DR. CONNELL: With a moderator, then outside the calandria tube.

MR. PENN: Correct, sir.

There is, if you like, a whole forest of calandria tubes and the moderator is within it.

DR. CONNELL: Surrounding throughout the whole calandria chamber.

MR. PENN: Yes.

DR. CONNELL: Right. There is coolant flow then through the pressure tube as indicated on page 5 of your overheads, and this flows then to the headers and steam generators?

MR. PENN: That's quite correct, sir. It flows through the outer headers, they are the ones at the extreme left and right to the steam generator and then returns through the inlet headers to the reactor.

DR. CONNELL: Right. Now, I would like to understand something about the tritium problem.

This is essentially a nuclear reaction, the interaction of the neutrons with the heavy water with deuterium.

MR. PENN: It's an absorption of a neutron by deuterium oxide to form tritium oxide. It is just the additional of one neutron to the nucleus.

DR. CONNELL: Yes. So it remains as tritium oxide not as molecular tritium.

MR. JOHANSEN: Yes.

THE CHAIRMAN: Did you say something to that, Mr. Johansen? Did you have some answer to that that you wanted to make?

MR. JOHANSEN: Yes, I just agreed with Dr. Connell.

DR. CONNELL: Now, is this reaction predominantly in the coolant or in the moderator or both?

MR. PENN: It occurs at both.

DR. CONNELL: Which is predominant?

MR. KING: There is more moderator in the core at any one time, so it would be primary in the moderator. The moderator is resident the core -- it's only heavy water in the pressure tubes which is resident at any one time and hence acceptable to this absorption process. The rest of the heavy water is in steam generators and outlet headers in the headers, et

cetera.

DR. CONNELL: Can one of you give me some kind of quantitative figure for the generation of tritium, say, per days operation. Are we talking one part in a million or more or less?

MR. KING: I can't.

MR. DALY: I think that part of the difficulty we are having is that we replace the heavy water with fresh water periodically. On average when the station is running on a mature condition, the level of tritium in the moderator is about 10 times the level of tritium in the heat transport system, order of magnitude.

DR. CONNELL: When you say periodically, how often would that be? A week or two weeks?

MR. DALY: Pretty well on a small continuous basis. There are small leaks periodically and periodically the systems are topped up.

DR. CONNELL: Yes. In Exhibit 4 on page 5.5, if you have Exhibit 4 with you. I wasn't going to quote from it extensively, but there is a reference, in the left-hand column, towards the bottom it refers briefly to:

> Radioactive releases may occur in cooling water systems or air exhaust

ventilation systems as result of inadvertent discharges and spills.

Now, you described certain classes of incidents in which there are significant spills, but I take it there are others which are so small as to be undetected or unrecognized as special events; is that correct? I am thinking here primarily of tritium, tritiated water.

Would it be fair to say there are sort of acute incidents plus in addition to chronic emissions?

MR. JOHANSEN: Well, I did describe the so-called chronic emissions of tritium to water associated with normal operation of our plants, if that's what you are questioning.

DR. CONNELL: Yes. If you look at the pattern over a whole year, how much of the tritium emission would be attributable to recognizable incidents? Would you be able to account for most of it by some known fault or not?

MR. JOHANSEN: You are asking, if I understand your question, whether most of the emission is the result of a planned or controlled emissions as opposed to unplanned or accidental emissions?

DR. CONNELL: I am sorry, I didn't realize they were planned emissions. That confused me.

MR. JOHANSEN: Well, these are emissions that are monitored and that we expect. In that sense, I suppose they are anticipated or routine emissions as opposed to emissions associated with abnormal or accident conditions.

DR. CONNELL: Let's discuss the normal ones for a minute then. Where do they come from? You must have some idea.

MR. JOHANSEN: Yes. As I indicated in my direct, they are typically the result of leakage of small quantities of heavy water that has become tritiated whilst in the reactor, and the leaked heavy water in either vapor form can be released through the ventilation system after a drying stage which is part of the control system to recover as much of this heavy water, which is expensive to produce in the first place, and thereby minimize the emission of tritium to the atmosphere.

[4:20 p.m.]

Another fraction of the H(2)O may be picked up in the collection and recovery system and wind up by going to the active liquid waste management system which then, on a batch basis after being monitored for radioactive levels, may be released to the cooling water discharge, and in that sense it's a

controlled release. So there are those two emission pathways.

DR. CONNELL: Do you know whether the - if I can continue to use the term chronic leakage or planned leakage - whether it comes from the coolant circuit or the moderator?

MR. JOHANSEN: Well, I'm probably not the best one to answer that.

MR. PENN: Maybe I can try and answer. We've always recognized that with such a large piping system you could never expect that it would be totally leak tight all the time and that's why there's a vapor recovery and heavy water recovery system within the station.

And these minor leaks that can't be seen but can be detected with monitors typically come from valve stems or flange joints, although most of the piping in the plant is seam welded, but there are obviously places that one has to be able to take the pipes apart for maintenance, and this is the type of cause of loss of heavy water which would be tritiated in the form of vapor.

DR. CONNELL: You're referring mainly to the coolant circuit then?

MR. PENN: I would be referring to the

high pressure systems, yes, the coolant system.

DR. CONNELL: What is the operating pressure, Mr. Penn?

MR. KING: Well, as Mr. Penn just suggested, most of the leakage would come from the high pressure heat transport system because it's at typically 10 megapascals which is around 1,500 psig, where the moderator system is at a very small pressure, perhaps the moderator pump discharge going back into the moderator would be 40, 50 psig, so there just isn't the driving force in the moderator piping to get as much out as there is in the heat transport piping.

DR. CONNELL: No. Is there ever any transfer of tritium into the steam channel itself?

MR. KING: You're referring to---

DR. CONNELL: In the heat exchanger.

MR. KING: --moving from the heat transport system to the light water, boiler water and steam system?

DR. CONNELL: Yes.

MR. KING: That would only occur if there were small leaks or leaks of any sort in the steam generator tubing.

DR. CONNELL: Does it happen?

MR. KING: Yes, it does happen.

DR. CONNELL: Is that a serious causal --

MR. KING: There are limits in operation on the amount of leakage that is allowed before the plant has to be shut down and that tube typically plugged.

DR. CONNELL: Right. The isotopes of krypton and xenon that are emitted, these may come from the fuel itself, that would be the predominant source, I take it. And what are those isotopes; are they long-lived isotopes?

MR. JOHANSEN: They're short lived.

DR. CONNELL: But what are the half-lives, roughly?

MR. JOHANSEN: We're talking about days.

MR. KING: I believe there's a table of half-lives in Exhibit 507 which is the material, the Health Effect Report which was tabled. I believe there's a table of half-lives for the noble gases in there.

DR. CONNELL: Thank you. And are the decay products stable isotopes?

MR. JOHANSEN: Eventually. Just as a matter of interest, you were asking about xenon. The half-life of xenon 133 is 5 days approximately, xenon 135 is about 9 hours, so reasonably short.

DR. CONNELL: There are no long-lived daughters in the chain?

MR. JOHANSEN: No.

DR. CONNELL: Dr. Whillans is looking puzzled.

MR. JOHANSEN: I don't have a number for krypton handy.

DR. WHILLANS: I would prefer to look it up to be sure, but I believe one of the xenons has a minor long-lived daughter.

MR. KING: Well, I have the table in front of me right now. The xenon's range in --

THE CHAIRMAN: Are you referring to 507?

MR. KING: I am talking about Exhibit 507.

THE CHAIRMAN: Page...?

MR. KING: Page 4-18. And the half-lives range for xenon 131 metastable, 12-day half-life. The other isotopes vary: 5.3 days, 2.2 days, 9.2 hours, 15 minutes, and 14 minutes. Those are all isotopes of xenon.

The krypton half-lives -- krypton 85, 10.7 years; krypton -- another metastable form of krypton 85, 4.5 hours; krypton 87, 1.1 hours; krypton 88, 2.8 hours.

DR. CONNELL: Thank you. Any additional information?

DR. WHILLANS: Well, I guess just to complete my comment, I believe one of the caesiums that's listed in this table is fairly long lived, but I'm not sure of it's half-life.

Oh yes, it is, sorry

MR. KING: You were just asking noble gases?

DR. CONNELL: Yes.

DR. WHILLANS: The caesium daughter of xenon 135 has a half-live of 2.3 million years.

DR. CONNELL: Sorry, is that one that's not in the table that you --

DR. WHILLANS: It's on the table as the daughter of the xenon 135. The caesium listed beside it is the daughter.

DR. CONNELL: I haven't got mine in front of me.

DR. WHILLANS: Oh, sorry.

DR. CONNELL: What page is this?

DR. WHILLANS: Page 4-18.

DR. CONNELL: I take it that's not of high abundance for any products?

DR. WHILLANS: Right. The limiting

concern about exposures to the noble gases is primarily direct irradiation.

DR. CONNELL: Right. Someone on the panel mentioned the monitoring of emissions from the RWO at Bruce, but I don't think you provided any data. Have there been significant emissions?

MR. JOHANSEN: In fact, one of the charts that I happened to attach, I didn't show it on the overhead, but one of the charts that I included in Exhibit 519 I chose, I think it was --

MR. PENN: Page 48.

MR. JOHANSEN: 48, shows the emission trend from the waste volume reduction facility at the waste management site at Bruce and, again, as was the case with the example that I showed on the overhead, the emissions are well below the one per cent target.

And in the source document from which these charts were selected, there are similar charts for all of the other facilities at Bruce.

DR. CONNELL: These are just air emissions. Are there any water emissions?

MR. JOHANSEN: In the source document, and this is the health and safety division annual report that was given in response to Interrogatory 9.17.36, you will find similar charts for the rest of

the waste management site and the water emissions shown for that facility are similarly below the one per cent target.

DR. CONNELL: Has that interrogatory been cited before?

MS. HARVIE: Yes, it has, Mr. Chairman.

THE CHAIRMAN: Yes, 15.

DR. CONNELL: Thank you. And are the storage bays also covered in that?

MR. JOHANSEN: Excuse me, I didn't...

DR. CONNELL: Are the storage bays also covered in that document?

MR. JOHANSEN: They are to the extent that the emissions from fuel storage bays are included in the station emissions, yes.

DR. CONNELL: And I just have one question about the health data, it concerns the so far I believe unique findings at Sellafield which I believe to be a nuclear reprocessing plant; is that correct?

DR. WHILLANS: It does reprocessing, it also develops some power, does research, it's a mixed complex and has been for many years.

DR. CONNELL: Is there anything about the environment there which might lead you to expect singular health effects not found at normal power

stations?

DR. WHILLANS: Well, I think I described in the evidence that other similar sites have not shown the same association.

DR. CONNELL: Yes, you mentioned Dounray too.

DR. WHILLANS: Dounray as an example.

DR. CONNELL: Is also a reprocessing site?

DR. WHILLANS: That's right.

DR. CONNELL: Are there any differences between Sellafield and Dounray?

DR. WHILLANS: Well, there's been a lot of speculation of course about what the possibilities might be. There are a lot of chemicals used, not just in the reprocessing but in the research facility.

Geographical sighting is a little bit different and there has been suggestion that the actual physical environment rather than the presence of a nuclear station itself might be responsible for these.

And one of the key theories, I guess, about the cause of this has to do with the influx of new populations into rural areas, this so-called viral hypothesis, but I don't think any of these is proven yet.

DR. CONNELL: Just turning to emissions for a moment, I noted down radioactive particulates and I don't think I discovered exactly what that term means. Could someone define radioactive particulates for me?

MR. JOHANSEN: It's a general term that we use to describe a number of fission products and activation products that arise in the reactor system and attach themselves to dust and, hence, the general term particulate.

DR. CONNELL: This is relevant then only to air emissions?

MR. JOHANSEN: Yes, that's right.

DR. CONNELL: And not to water emissions?

MR. JOHANSEN: We use the word particulate in the context of air emissions and I referred also to, under the heading of water emissions, to another group of particulates which we generally label gross beta gamma. These are dissolved or suspended particulates.

So there are particulates that could go either way, but generally speaking when we talk about particulates, we're talking about airborne emissions.

DR. CONNELL: Can you tell me a little bit about the chemistry of the particulates?

MR. JOHANSEN: Well, they would be typically the --

DR. CONNELL: Similar to used fuel?

MR. JOHANSEN: Yes, many of them would be. The isotopes of elements like caesium and zirconium and cobalt, for example, would be formed in the reactor during the fission process or as a result of neutron absorption in the reactor system and would be monitored and emitted in a controlled way through high efficiency particulate air filters if it were being released to the environment.

DR. CONNELL: Would it be fair to say if there were an accidental release then, this would be the most hazardous of the possible emissions?

MR. KING: It depends on, of course, the amount, the half-lives and the energy of any particles that would come off of the radioactive species.

Generally the releases in an accident would be in gaseous form, noble gases which are not filterable, they would be iodine or various chemical forms of iodine which can be attracted to charcoal filters or onto other components or into water which is in the environment.

Particulates can act like gases if they're in an aerosol form. They are very fine

particles and they get attached to dust or whatever and act in -- they're referred to as aerosols.

The particulates, a good one is the caesiums. Caesium 137 with its 30-year half-life which, if it was released, it would deposit generally on the ground and depending on -- and the rate of deposit depends on atmospheric conditions and whether it's raining, et cetera.

DR. CONNELL: The figures that you've given for example on pages 46, 47, 48, these are all calibrated against DEL, so you can't really compare one with another, but I would assume that the DEL for the particulates is probably more stringent than for, say, tritium. Is that the case?

DR. WHILLANS: The DELs are listed in fairly small print but just at the top of the figures.

DR. CONNELL: Oh, I see, yes. These are curies?

DR. WHILLANS: Yes.

DR. CONNELL: Oh. I think that does verify what I've just said then; doesn't it?

DR. WHILLANS: Yes.

DR. CONNELL: Of the order of 10 to the 6th compared to tritium. Thank you.

Turning to pressure tube failure for a

moment - this was Mr. Penn I think - apart from the garter spring problem, you referred to the hydride penetration and to the elongation effect as the two principal technical problems.

Do I understand that the present generation of pressure tubes are no longer susceptible to the hydride effect or at least not within the lifetime?

MR. PENN: Well, delayed hydride cracking in zirconium occurs down the temperature gradient and, therefore, it's associated with when the hot pressure tube is in contact with the cold surface.

DR. CONNELL: I see.

MR. PENN: It requires also stress to be applied to cause delayed hydride -- well, what happens first is that the ingress -- well, let me start again.

It requires three factors to cause delayed hydride cracking. It requires a temperature gradient to be caused to happen, it requires stress in the metal to have to act at the same time, and it requires the presence of free hydrogen or deuterium to ingress at that location.

[4:40 p.m.]

What happens is that the hydrogen or deuterium goes into solution in the zirconium alloy and

remains in solution until what is termed total solid solubility limits are reached when the platelets of zirconium hydride and precipitate out and then not in solution of the metal, and delayed hydride cracking occurs when these platelets of hydride get orientated in a certain direction and then hydride is formed in the metal and this whole process takes a very long time. It doesn't happen in weeks or months; it takes years.

Then as zirconium hydride occupies a bigger volume than the parent metal, it causes further stresses and the blisters Mr. Daly talked about crack, and that's the process of delayed hydride cracking. And it is prevented by removing any one of or all of the three conditions that cause it to happen.

So, if you have got enough garter springs in the channel and they are in the right place and the pressure tube can't touch the calandria tube, you don't form the temperature gradient to cause the process to start.

DR. CONNELL: So in fact that is a problem of the past then.

MR. PENN: We believe so. We now have what we call tight garter springs that clasp the pressure tube and don't move and we believe that's the

solution.

DR. CONNELL: With regard to the remaining problem, the elongation, I got the impression, I can't seem to find the overhead at the moment, but I got the impression that there were some quite striking differences in life expectancies even within Bruce "B", for example, that two of the reactors seem to have considerably shorter tube lives than the other two.

MR. PENN: Yes. Well, the lives aren't set by either delayed hydride cracking or axial elongation; they are set by Hydro's desire, first of all, not to exceed 30 years life at this point in time, and secondly to avoid retubing two reactors, shall we say, at Bruce "B", at one and the same time in parallel. And that's why these dates have been chosen, and the lives as you mentioned for Bruce 5, for example, is 26 years.

DR. CONNELL: What is that figure number?

MR. PENN: I'm sorry, this is page 63 of our Exhibit 519.

DR. CONNELL: Thank you.

MR. PENN: And you can see that in Bruce "B", of course, Bruce 5 was the first unit -- I'm sorry, Bruce 6 was the first unit to go into service.

We, in our planning, have decided to start retubing Bruce 5 first, February 2011, and the consequential result is that those tubes would have 26 years life from a depreciation point of view. And whereas Bruce 6, which would be retubed in May 2013 and would follow the completion of work in Bruce 5, would then have 29 years, and Bruce 7, because its startup date was a year and a half later than Bruce 6, when it's being retubed in 2015, also happens to have 29 years. And this is how these particular service lives have come about.

Now, Hydro, given ongoing knowledge of pressure tubes, may or may not decide to retube them exactly on those dates. Clearly, if we can get more life safely out of them and economically out of them, we will do so. But those are our present plans.

DR. CONNELL: This is true also of Bruce "A" where the difference in the tube life is even more striking.

MR. PENN: Well, there is another reason for Bruce 1 and 2 being less than Bruce 3 and 4, and that is this question of provision of axial elongation. And the fact that Bruce 1 and 2, and I ask Mr. Daly to correct me if I am wrong, Bruce 1 and 2 doesn't have four garter springs in it, I believe it has two garter springs, and we have more concern for those units for

delayed hydride cracking than Bruce 3 and 4.

There was a change in design at about that time that they were being built.

DR. CONNELL: Thank you.

Can you confirm that, Mr. Daly?

MR. DALY: That's confirmed, yes.

DR. CONNELL: Thank you.

With regard to the power generator cracks, I would like to know whether the experience you have had is specific to the nuclear option or would this have been as likely to happen in the current generation for fossil stations?

MR. DALY: This is just as likely to happen with a fossil station for a generator of the same size. I am not aware of any specific failures of this particular manufacturer's generator on a fossil station, but by and large the generators on our fossil stations are very similar to the generators on the nuclear stations. The steam conditions are slightly different, the higher pressure, higher temperature steam on the fossil side, so that the turbines are -- there are some slight differences, but the generators are essentially the same.

So yes, it could equally happen to a fossil station.

DR. CONNELL: The fact that the capacity is 880, it might as likely happen at the 500 megawatt level, might it?

MR. DALY: I think there is perhaps slightly more potential with the larger machines. This was a problem with the overall flexibility of the shaft, and as machines get larger, you have to be a little more careful in the design and balancing of the machines.

So I would say, subject to what Mr. Penn is going to say, perhaps it's something that you have to be more careful with, with the larger machines.

MR. PENN: I can confirm that the problem with the generator rotors at Darlington was related to the degree of flexibility in the shaft itself, creating high tensile stresses locally. And in fact, the final solution, which is at Brown and Boveri's cost, is to increase the diameter of the rotor shaft in the area where we had problems.

DR. CONNELL: I take it their liability amounts just to replacement, not to cover the debt service related to any delays.

MR. PENN: It relates to replacement of the rotors. There is no consequential damage where they are required to replace energy lost.

We would love to gain a contract with clauses of that nature, but it's not possible to do business with companies on that basis.

DR. CONNELL: With regard to fuel, I wonder if I could just ask you to give us a brief account of the provision for the Elliot Lake contract extension, the implications of that arrangement with respect to its overall cost.

MR. PENN: I am afraid, Dr. Connell, I am I am not familiar with an extension that you are speaking of. I pointed out in my direct evidence that we are in fact terminating contracts in 1993 and 1996 with Denison Mines and Rio Algom.

DR. CONNELL: I was relying on press reports and I thought the contracts were going on longer than Hydro had initially intended them to.

MR. PENN: Well, I will certainly confirm whether I am right or wrong with you. I don't have that knowledge.

DR. CONNELL: Thank you.

Finally, I would just like to draw the attention of the panel to transcript Volume 16, which was part of Panel 2. I asked a question about some data on isotopes in used fuel. This appears on page 2890 and 2891, and I think it was Ms. Ryan told me, and

I quote: "The people on Panel 9 would have that information."

So may I leave that with you for further study.

Thank you.

THE CHAIRMAN: I think we might adjourn now for the day and we will start tomorrow morning at ten o'clock with the motion by Energy Probe; is that correct?

MS. McClenaghan: Yes.

THE CHAIRMAN: When that is over, we will start the cross-examinations.

The witnesses don't have to be here for the motion. Of course, if they would like to come, they can, but they don't have to be here for that.

We will adjourn until tomorrow morning at ten o'clock.

THE REGISTRAR: Please come to order. This hearing is adjourned until ten o'clock tomorrow morning.

---Whereupon the hearing was adjourned at 4:52 p.m. to be resumed on Thursday, March 26, 1992, at 10:00 a.m.

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